Energy Research and Development Division
FINAL PROJECT REPORT

COMMUNITY INTEGRATED RENEWABLE ENERGY PROJECT

Project Summary Report

Appendices A - G

Prepared for: California Energy Commission
Prepared by: Arup, for the San Francisco Department of the Environment

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LIST OF APPENDICES

APPENDIX A:
Task 2 Community Distributed Generation (Regulatory Policy)

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ARUP

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CHAPTER 1: Introduction

1.1 Project Description

The CIRE Project will assess the feasibility of community energy, integrating district heating and cooling, renewable electricity, storage and energy recovery, demand response, and smart distribution technology to serve members of a community with their energy needs.

The CIRE Project consists of the following tasks and subject areas:

- Task 1: Administrative and Reporting
- Task 2: Distributed Generation Connected to the Electricity Network
- Task 3: Enabling Technologies
- Task 4: Energy Storage and Generation
- Task 5: District Thermal Energy Concept

This report provides our preliminary findings for Task 2: Distributed Generation Connected to the Electricity Network. The goal of this task is to determine the regulatory barriers that prevent increased penetration of renewable DG onto the electricity network. This report is focused on assessing the regulatory challenges to increasing CIRE projects in California.

This report has the following scope:

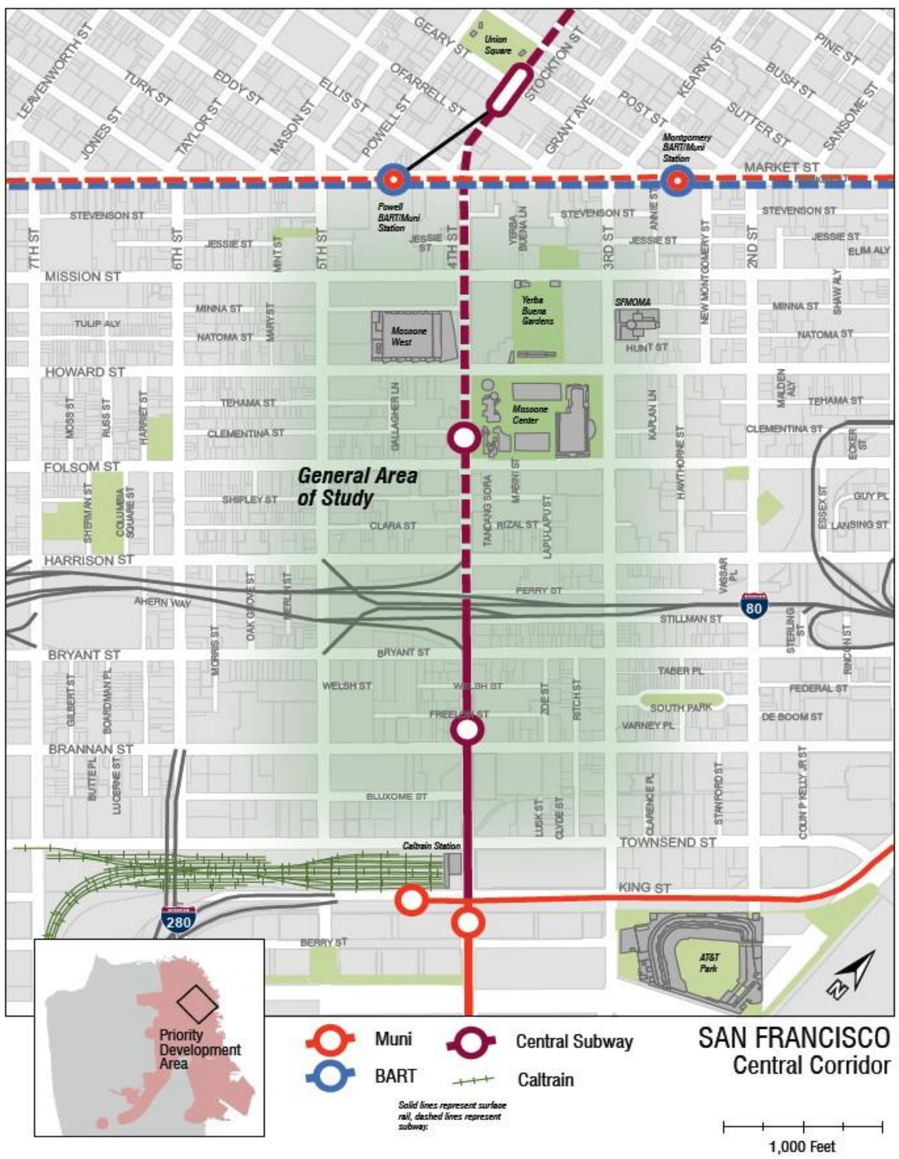
- identify applicable codes, regulations, and standards to CIRE projects;
- investigate the regulatory barriers to be overcome to implement a community-scale project;
- work with the regulators and utilities to discuss concerns;
- work with utilities to overcome any identified barriers with a mutually satisfactory solution;
- review strategies to replicate CIRE throughout other areas of California.

1.2 Central SoMa

In San Francisco, 56% of greenhouse gas emissions are associated with lighting, heating, and cooling buildings. The City and County of San Francisco (CCSF) is committed to developing and implementing aggressive and diversified approaches to reducing these emissions while continuing to absorb anticipated regional population growth. One such approach is to plan carbon-free community-scale energy resources locally and regionally. Another is to increase jobs and housing in transit-oriented neighborhoods.

Central SoMa (South of Market) is a dense, transit-rich area of San Francisco that extends from Second Street to Sixth Street and from Market Street to Townsend Street in the city's South of Market area. The area has been identified as a priority development area by the Planning Department, and is the subject of a significant rezoning effort that encourages sustainable growth and creates substantial opportunities to align energy, transportation, water, and waste infrastructure systems. In addition to identifying the renewable energy resources and enabling technologies that could be appropriate for this district, the CIRE Project will identify ways CCSF can advance community-scale energy in this neighborhood. These efforts include providing a strategy to coordinate multiple public and private interests, including identification of all key institutional stakeholders and relevant regulatory frameworks.

Figure 1: San Francisco Central SoMa



Source: City and County of San Francisco, Planning Department

With the addition of the Central Subway along and under Fourth Street (now under construction and scheduled to begin operation in 2018), undeveloped or underdeveloped parcels in the transit corridor offer a major development opportunity. CCSF anticipates approximately 10,000 new housing units and 35,000 jobs in this area. The Central SoMa Plan, released in draft in April 2013, proposes rezoning this area for dense, transit-oriented, mixed-use growth and provides opportunities to capitalize on rezoning to incorporate district-level energy infrastructure.

In addition to providing local energy, creating CIRE projects will greatly enhance the resiliency of Central SoMa. The ability to generate power and provide local energy for such services as producing potable water and treating sewage is essential for both the immediate and long-term recovery from a large earthquake or similar disaster.

The Central SoMa CIRE Project has the potential to inform similar planning efforts in other parts of the state, particularly those with new development areas, major infrastructure projects, or significant revitalization planned, as well as existing, mature neighborhoods.

1.3 Community Integrated Renewable Energy

California leads the country in the deployment of renewable generation. California law requires state utilities to procure 33% of their electricity needs from eligible renewable resources by 2020. This policy is called the Renewable Portfolio Standard (RPS).

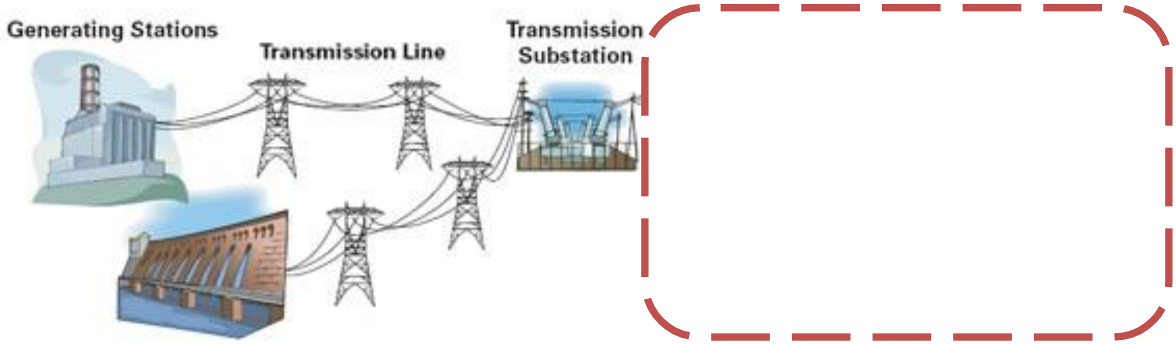
As a next step aimed at raising even further the State's ambitious renewable energy targets, Governor Jerry Brown has called for 12,000 MW of distributed renewable power to be generated by projects sized no larger than 20 MWs.

While the CEC has been tasked to work on how this target might be allocated amongst various programs and geographic or utility areas, it is broadly expected to include MWs from existing rooftop and ground mount programs, e.g., the California Solar Initiative, Renewable Auction Mechanism, Feed-in Tariffs and general renewable solicitations, etc.

To put the 12,000MW number into perspective, the California Solar Initiative (designed to support installation of solar PV systems under 1MW) has a goal of 1,940MW of installed capacity by 2016 and has currently reached the 1,659MW installed mark via approximately 160,000 installations since the program's launch in 2007 (*Peterson, 2013*). This 1,940MW target does not include publically owned utilities (which the 12,000MW target will apply to), but serves as a useful reference to the amount of renewable energy connections that could be required for small renewable energy systems.

In the context of this report, *local renewable power* is defined as generation installed on the distribution network so that benefits are gained locally. Such benefits include reduced system losses, energy security, deferred need for transmission lines and increased renewable energy content. Often these schemes are installed right at the load point, maximizing these benefits. The projects are typically sized from 1kW to 20MW and can be technologies such as photovoltaics, small wind, and biogas fuel cells. A key feature of CIRE projects is that electricity is generated and distributed within a community, defined in this project as the Central SoMa redevelopment area in the South of Market (SoMa) neighborhood in San Francisco.

Figure 2: Location of CIRE Projects in the Electric System



Source: Southern California Edison

Local community generation drastically shortens the distance between the location where energy is generated and the site where it is being used. This reduces the need for high voltage transmission infrastructure upgrades, as well as reduces the amount of energy being lost through transmission from generation source to customer site. The reduced reliance on large, centralized, combustion-based generation for energy needs will also lead to a significant reduction in carbon dioxide emissions.

Implementing CIRE projects will provide important advantages in California's drive for clean power — development of local resources, avoided costs of new intercity transmission or remote generation, additional consumer autonomy, greater resiliency and reduced greenhouse gas emissions.

This report assesses the current barriers to increasing community-based renewable energy systems and identifies enabling technology (such as a smart or microgrid) that would manage or facilitate renewable generation, distribution, and storage within a community.

Broad support for CIRE calls for new approaches and coalitions between consumers, community leaders, utilities, and power providers. These new approaches have to address the needs and desires of key stakeholders: utilities, consumers, businesses, and residents, along with health and environmental factors. An influx of new local generation is likely to require revised utility business models as we transition toward a new paradigm for our electrical grid.

The majority of the CIRE models identified in this report are generation projects that are not installed behind a single meter to exclusively serve on-site load. Community-integrated generation can take on many forms and many ownership models. This report considers the following scenarios:

1. Members of a community who have no on-site space for or access to renewable energy but who want renewable energy to supply their individual property/business.
2. A single, distributed campus community member who wants to install renewable generation behind their utility meter.
3. Community members within a single contiguous or multiple land parcel whose energy is provided by on-site, centralized energy generation.
4. Community members spread over multiple land parcels whose energy is provided by centralized energy generation and have the ability to separate from the wider grid and operate independently (microgrid).

CHAPTER 2:
California Electricity Markets

2.1 Markets and Utilities

California has a mostly regulated electricity system that is generally[2] divided into three parts: (1) generation, (2) transmission, and (3) distribution and energy sales.

Three main Investor Owned Utilities (IOUs) serve the majority of electric customers in California:

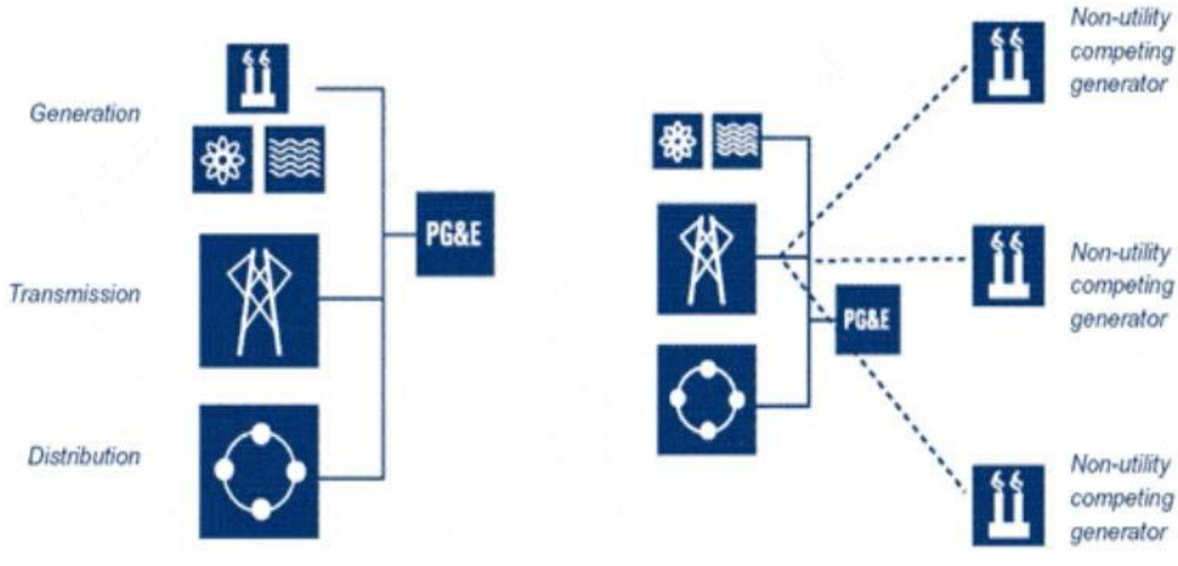
1. Pacific Gas and Electric (PG&E)
2. Southern California Edison
3. San Diego Gas and Electric

These large IOUs deliver electricity to around 70% of the state's electricity customers. The remaining electricity is delivered by around 50 smaller municipal, publicly owned utilities and co-ops. Examples of these alternative suppliers are the San Francisco Public Utilities Commission, Los Angeles Department of Water and Power, and Silicon Valley Power.

Prior to the 1996 Electric Utility Industry Restructuring Act (Assembly Bill [AB] 1890), utilities such as PG&E operated in a vertically integrated, regulated monopoly. The 1996 deregulation allowed competitive generation to enter the wholesale energy market in an effort to provide competitive wholesale energy pricing in California. This report does not discuss the effects of deregulation but notes some deregulation policy impacts on CIRE projects.

[2] Item (3) distribution and sales can be separated under certain electricity supply scenarios. This may include direct access, community choice aggregation and municipal power providers.

Figure 3: Utility Structure Before and After Deregulation



Source: SPUR (*Nimmons*)

2.1.1 Generation

Prior to deregulation, the IOUs owned the majority of the generation assets in California and operated as vertically integrated companies. Deregulation required the IOUs to sell at least 50% of their generation assets to independent power producers and sell power from their remaining assets through the California Power Exchange or CAISO in order to ensure that the wholesale energy generation market was a competitive market. The IOUs still own and operate generation assets that they were unable to divest during the wholesale generator deregulation period. In addition, IOUs are permitted to own new generation in California. New generation ownership by IOUs in California is subject to CPUC approval. The regulation of the transmission system and electricity markets by CAISO ensures that there is no bias to purchase wholesale electricity from particular generators, keeping the market competitive.

Today, the state's IOUs generate about 25% of California's electricity. Public power (such as Southern California Public Power Authority) generates about 17%, and about 58% comes from private-sector energy companies competing in the state's wholesale electricity market. (Smuntny-Jones, 2009)

2.1.2 Transmission

IOUs own approximately 70% of the Californian transmission system, while the remaining municipal, publically owned and co-op entities own the remaining 30%. (Smuntny-Jones, 2009)

With the exception of some municipal grids, the California transmission system is operated (not owned) by the California Independent System Operator (CAISO). The CAISO is a nonprofit, for-the-public interest entity responsible for ensuring the transmission system's reliability and making sure electricity is transmitted in a nondiscriminatory way that does not favor one area, user, or generator over another.

The utilities maintain ownership of their transmission facilities while operational control is the responsibility of the CAISO, which serves as the impartial liaison between the power plants and utilities. The utility receives revenue in their business model for the transmission of electricity throughout the system that they own and can make cases to extend the transmission system where required, subject to regulatory approval.

Not all of the wholesale energy purchased for use in California is produced in California. Utilities also buy power from the wholesale markets in neighboring states. This in turn requires out-of-state transmission. Transactions involving state-to-state energy transmission are regulated by the Federal Energy Regulatory Commission (FERC), an independent federal agency, as opposed to the local CAISO.

2.1.3 Distribution and Energy Sales

Electricity is distributed and sold by utility companies. The utility companies own and operate the distribution network that delivers electricity to customers. The utilities are responsible for the sale of electricity, billing, maintenance, fault rectification, upgrades, and construction of electricity assets.

In limited cases, large electricity users like retailers, manufacturers, commercial campuses, and universities buy their electricity directly from ESPs instead of the utility companies. This process is known as *direct access*. Direct access is discussed in more detail in Chapter 4, where we define its applicability to CIRE projects.

2.2 The Regulators

The IOUs are regulated by the state, while the municipal utilities are regulated by locally elected governing boards. Three state agencies and one federal agency perform the regulating roles in California:

1. The California Public Utilities Commission (CPUC) has both legislative and judicial powers. The CPUC's mission is to "serve the public interest by protecting consumers and ensuring the provision of safe, reliable utility service and infrastructure at reasonable rates, with a commitment to environmental enhancement and a healthy California economy." (*CPUC, 2013*) The CPUC regulates utility services and promotes competitive markets. A principle role of the CPUC is to review applications from the IOUs for electricity rate changes and to set rates for electricity customers. These rates are designed to provide the utilities with a reasonable return on investment and are based

on the cost the utilities pay to generate or purchase and transmit the electricity, along with the cost of various energy-related programs these companies are required to provide.

2. The CAISO oversees the operation of California's bulk electric power system, transmission lines, and electricity market. The mission of the CAISO is to "operate the grid reliably and efficiently, provide fair and open transmission access, promote environmental stewardship, and facilitate effective markets and promote infrastructure development." (*CAISO, 2013*)
3. The California Energy Commission has "responsibility for activities that include forecasting future energy needs, promoting energy efficiency through appliance and building standards, supporting energy research, licensing large power plants and supporting renewable energy technologies." (*CEC, 2013*)
4. The Federal Energy Regulatory Commission (FERC) is an independent agency that regulates the interstate transmission of electricity, natural gas, and oil. FERC regulates wholesale energy generation with interconnection at the transmission level.

2.3 Utility Regulation

In California and most other parts of the world, a utility will determine its business model in response to the regulatory regime that it operates under. Therefore, regulators play a significant role in shaping the way electricity utilities operate under their jurisdiction.

In California, there is a competitive generation market following deregulation in 1996. Distribution and Sales is a regulated monopoly where retail competition is somewhat limited, although it does occur in certain geographic areas within the service territories of the IOUs.

Regulation in California has resulted in utilities employing a cost-for-service business model. A utility will spend capital to build an asset and is permitted to make a reasonable return on the asset that has been constructed. Regulators assess the need for the utility to build the asset in the first place and determine a reasonable return on investment.

This form of regulation does not incentivize utilities to develop different business models. Governments around the world are trying to understand how regulation may need to change in order to facilitate the desired changes to our electricity system and generation portfolio.

An ideal regulatory framework would allow the utilities to be compensated fairly for the service that they provide while incenting utilities to achieve the state's broader goals. These boarder goals are to reduce the reliance on fossil fuels, provide customer satisfaction, provide a reliable network, provide affordable energy and have a very limited environmental impact among others.

The current regulatory framework does not enable utilities to develop new business models to provide this innovation. Other parts of the world, such as the United Kingdom, are introducing performance-based regulation, which has the ability to incentivize innovation and efficiency. The final draft of this report will suggest suitable policy amendments to facilitate CIRE projects.

CHAPTER 3: Interconnection

Every CIRE project will have a connection to the wider electricity grid and will therefore be required to obtain an interconnection.

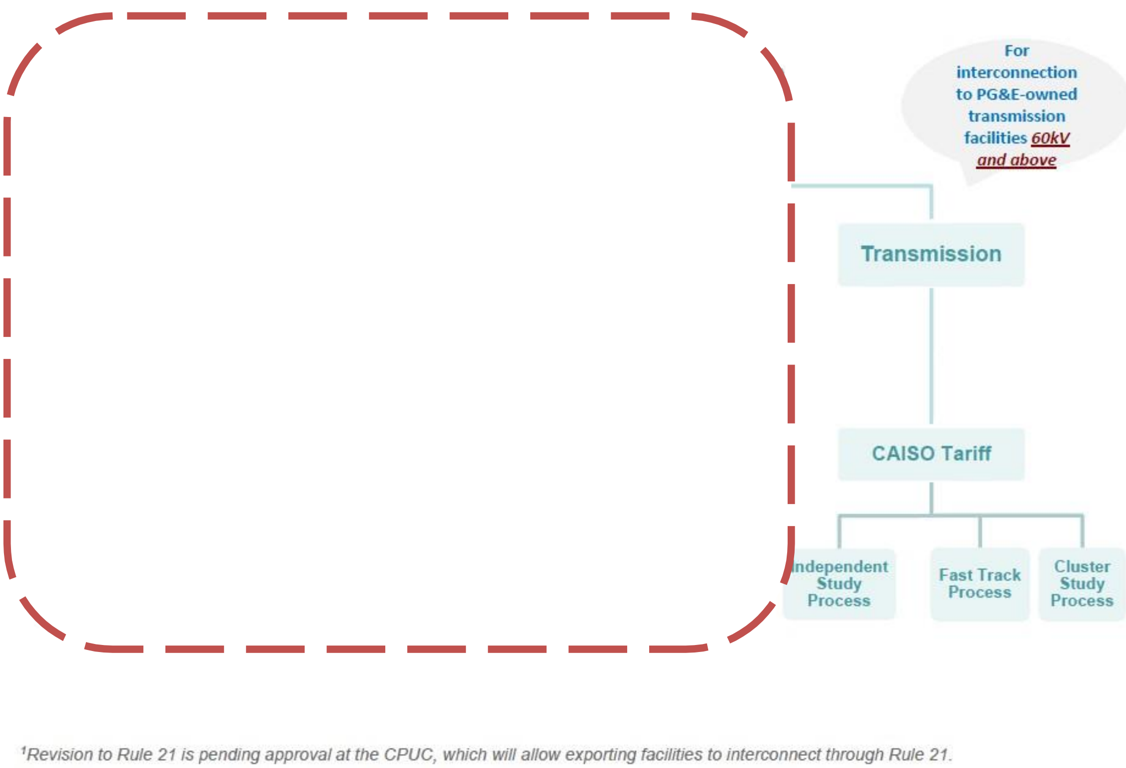
This section defines the various interconnection options suitable for a CIRE project. The definition of the interconnection process is important in understanding the rate at which the generation asset will receive bill credits or direct payments and will play a part in the project's economic performance.

3.1 Overview

CIRE projects by their very definition involve communities. Communities contain businesses, residential homeowners and tenants, and other electricity consumers such as public facilities, neighborhood services and recreational facilities that make up a community. CIRE projects will always connect to the utility grid at the distribution level by virtue of their location, and would typically be under 20MW, and therefore would count towards Governor Browns 12,000MW local renewable energy goals.

Figure 4 shows the interconnection options that are available to CIRE projects.

Figure 4: Generator Interconnection



Source: PG&E

3.2 Electric Rule 21

At the community scale, Electric Rule 21 ("Rule 21") is likely to be the interconnection option applicable to the majority of CIRE projects.

Rule 21 is a set of regulations that describes the interconnection, operation, and metering requirements for distributed generators to be connected to a utility's electric system. The CPUC has jurisdiction over the Electric Rule 21 tariff. The Rule 21 tariff and the related CPUC-approved interconnection agreements are generally the same for each of California's IOUs.

Within Rule 21 there are various paths that can be taken to interconnect generation, with increasing studies and fees required for larger generators, and a more streamlined option for smaller generators. There are both retail and wholesale energy contracts available within Rule 21.

Rule 21 applies to generators that fall into one of the below categories:

- generate power for the applicant's own retail use only and do not export power to the electric grid ("non-export");
- generate power for the applicant's own use and for export to the electric grid for credit on their retail PG&E bills;
- operate as qualifying facilities, as defined by the FERC's Public Utility Regulatory Policy Act (PURPA), that sell (or export) all of their energy to the grid for sale to a California IOU through a wholesale PURPA Power Purchase Agreement (PPA).

3.2.1 Net Energy Metering

Net energy metering (NEM) is a renewable energy billing arrangement that currently allows customers with eligible DG to credit the DG system's electricity production against their on-site electricity use over the course of a month, even if the system primarily exporting (such as with a residential solar system during the day), and thus receive compensation for the electricity their DG system generates at the full retail value of the electricity use it offsets. Under NEM, when the installed DG produces more electricity than the customer demand, the excess energy automatically exports to the utility grid. Customers that generate a net surplus of energy at the end of a 12-month period can receive a payment for this energy under special utility tariffs.

NEM is available for systems of up to 1MW in size. For generation systems that are greater than 1MW in size, the customer has the option under the Rule 21 tariff to install the first MW of generation under the NEM agreement, being compensated at the full retail rate for exported energy, and the remaining generation as non-NEM generation, which may be compensated for at a lower wholesale value of the generated exported energy.

3.3 Wholesale Distribution Tariff

All wholesale generator distribution interconnections are governed by the IOU's wholesale distribution tariff (WDT).

There are several types of wholesale generation interconnection options:

- Distribution – projects that interconnect with a utility's distribution system, generally at a voltage level below 60 kilovolts (kV). These projects are governed by a WDT and are likely to be a suitable interconnection vehicle for CIRE projects.
- Transmission – projects that interconnect at a voltage level of 60kV or higher. These projects are governed by a CAISO tariff. It is not expected that this interconnection vehicle will be suitable for CIRE projects.
- Qualifying facilities – facilities that interconnect with a utility's transmission or distribution system, producing wind, hydroelectric, biomass, waste, or geothermal energy and sell energy to utilities at a wholesale rate. Qualifying facilities can also be cogeneration facilities that produce electricity and another form of thermal energy, and may be suitable for certain types of CIRE projects.

3.4 Summary and Fees

All utility interconnection processes have defined response timelines and options for fast track or detailed studies depending on the rating of the renewable generation being connected. Table 1 provides a summary of the various interconnection fees and required studies relevant to CIRE projects.

Table 1: Interconnection Summary

	Rule 21 <1MW	**Rule 21 >1MW**	**WDT**
MW Limit	1MW	None	None
Application Fee	$800	$800	$800
Fast Track Process Limits	Generators under 1MW typically follow a fast track process	≤3MW	≤2MW on 12kV ≤3MW on 21kV ≤5MW on higher voltages
System Impact Study (5MW or less)	N/A	Required, with $10k deposit	Required, with $10k deposit
Facilities Study	N/A	Required, with $15k deposit	Required, with $15k deposit
System Impact Study (>5MW)	N/A	Required, with $50k + $1k/MW (maximum of $250k) deposit	Required, with $50k + $1k/MW (maximum of $250k) deposit

The study deposits are used to cover prudent costs incurred by the utility to perform and administer the interconnection studies. Should the prudent costs be less than paid by the applicant, the utility shall refund the difference to the applicant.

CHAPTER 4:
Identify applicable codes, regulations, and standards

The development and deployment of CIRE projects in California will depend, in large part, upon the status of a multitude of policies and regulations, particularly at the state level.

These policies can act to encourage and enable (or discourage and prevent) private and public utilities, electricity service providers, and end users to include community DG as a key asset in meeting the state's ambitious renewable energy targets and greenhouse gas emission reduction goals.

This section provides identification of the relevant legislative and regulatory issues relating to CIRE developments. The section reviews the following regulations:

- California Public Utilities Code
- AB 117: Community Choice Aggregation
- SB 43: Shared Renewables
- Ancillary Market Participation
- electricity rates
- AB 327: Net Metering and Residential Rate Reform
- SB 32: Renewable feed-in-tariffs
- SB 594: NEM Aggregation

4.1 California Public Utilities Code

The California Public Utilities Code is the governing code in California pertaining to the regulation of utilities and sales of electricity. The code is important to be researched from the context of a CIRE project as the code will determine who can generate power, under what conditions, what they can do with the electricity produced, and what regulatory framework the CIRE owner will have to comply with. The code clearly defines the trigger levels that will require a CIRE owner to be regulated as an electric corporation (utility).

Section 216 of the Public Utilities Code defines a public utility as follows:

> "Public utility" includes every common carrier, toll bridge corporation, pipeline corporation, gas corporation, electrical corporation, telephone corporation, telegraph corporation, water corporation, sewer system corporation, and heat corporation, where the service is performed for, or the commodity is delivered to, the public or any portion thereof.[3]

Section 217 defines an electric plant as follows:

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[3] California Public Utilities Code, Section 216

"Electric plant" includes all real estate, fixtures and personal property owned, controlled, operated, or managed in connection with or to facilitate the production, generation, transmission, delivery, or furnishing of electricity for light, heat, or power, and all conduits, ducts, or other devices, materials, apparatus, or property for containing, holding, or carrying conductors used or to be used for the transmission of electricity for light, heat, or power[4].

Section 218 defines an electrical corporation as follows:

218. (a) "Electrical corporation" includes every corporation or person owning, controlling, operating, or managing any electric plant for compensation within this state, except where electricity is generated on or distributed by the producer through private property solely for its own use or the use of its tenants and not for sale or transmission to others[5].

(b) "Electrical corporation" does not include a corporation or person employing cogeneration technology or producing power from other than a conventional power source for the generation of electricity solely for any one or more of the following purposes:

(1) Its own use or the use of its tenants.

(2) The use of or sale to not more than two other corporations or persons solely for use on the real property on which the electricity is generated or on real property immediately adjacent thereto, unless there is an intervening public street constituting the boundary between the real property on which the electricity is generated and the immediately adjacent property and one or more of the following applies:

(A) The real property on which the electricity is generated and the immediately adjacent real property is not under common ownership or control, or that common ownership or control was gained solely for purposes of sale of the electricity so generated and not for other business purposes.

(B) The useful thermal output of the facility generating the electricity is not used on the immediately adjacent property for petroleum production or refining.

(C) The electricity furnished to the immediately adjacent property is not utilized by a subsidiary or affiliate of the corporation or person generating the electricity.

(3) Sale or transmission to an electrical corporation or state or local public agency, but not for sale or transmission to others, unless the corporation or person is otherwise an electrical corporation.

In summary, the identified code sections define a CIRE owner as an electrical corporation or public utility if the CIRE owner produces and distributes electricity for sale to parties other than the generation owner and/or the tenants of the individual building or property where the generation is located.

There are exclusions to the above statement. Within section 218, the code makes it clear that the generator owner is not defined as an electric corporation if the generation station uses

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[4] California Public Utilities Code, Section 217

[5] California Public Utilities Code, Section 218

cogeneration or non-conventional sources[6] to produce electricity, unless the electricity is sold to more than two adjoining properties, or the properties that it is sold to are across a public right-of-way (i.e. the power must be distributed across a public right-of-way).

4.2 AB 117: Community Choice Aggregation

Community Choice Aggregation (CCA), authorized by AB 117 in 2002, is a program available within the service areas of IOUs that provides additional retail choice for customers. The program allows cities, counties, and other qualifying governmental entities to purchase and/or generate electricity for their participating residents and businesses. A CCA cannot be a private for-profit entity; the CCA has to be a qualifying governmental entity. The local utility continues to deliver and be compensated for distributing the electricity through its transmission and distribution system, and for providing meter reading, billing, and maintenance services for CCA customers.

CCA providers may procure a different mix of energy resources than that offered by their local utility. Customers that take service from a CCA will stop paying the local utility's rates for generation but will instead pay the CCA's rates. In addition to the CCA rates, customers are also responsible for the power charge indifference adjustment (charges from the IOUs related to procurement obligations made prior to their departure), a franchise fee surcharge, and other state-imposed fees and taxes. In California, CCA's have primarily been set up to provide customers with a higher renewable energy content electricity product than is provided by the incumbent utility, though reducing costs to procure that power is another important criteria in many CCA's.

Several communities in California are implementing CCA. CCA allows the implementing government the opportunity to:

- gain local control of electricity supply pricing and generation supply decisions;
- create local economic benefits by contracting for CIRE installation and procurement;
- accelerate the transition to clean power.

State law requires that customers within a CCA's member jurisdictions be enrolled in the CCA service unless they choose to opt out and remain with the incumbent utility.

In California, Marin County created the first active CCA in the state which now also includes the city of Richmond. The CCA offers both a 50% renewable energy option and 100% renewable energy option to its customers.

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[6] Conventional energy resources are electric generation facilities or technologies that have been in practical use for a long time or which represent the majority of generation resources in use (i.e., coal, natural-gas, nuclear). At the time of writing non-conventional sources of generation include renewable generation sources such as solar, wind and bio-gas fuel cells.

The Sonoma region created its CCA, Sonoma Clean Power, in 2013. It includes the county of Sonoma and the cities of Windsor, Cotati, Sebastopol, and Sonoma. The program will deliver electricity to the first 20,000 customers in May 2014. The base option for electricity has a 33% renewable content (compared to the incumbent's mid-20% renewable supply mix expected during the same time frame). The forecasted rates are expected to be between 1.8% below and 1.1% above the incumbent utility's rates. The program also offers a 100% renewable option that is available for an estimated $10 to $15 monthly premium for residential customers.

San Francisco's CCA program, CleanPowerSF, has been under development since 2004. The program is currently designed to provide San Francisco with a 100%, California-certified renewable energy product, at a small price premium. There is no launch date set for CleanPowerSF.

4.3 Senate Bill 43: Shared Renewables

SB 43 is a community aggregation scheme for renewable generation. Approximately 75% of Californians (Denholm, 2008) cannot install renewable generation on their home or business, due to a variety of reasons such as lack of space, renewable energy resource, a tenant within a building, or lack of financial credit.

The bill was signed by Governor Brown in October 2013 and will go into effect in 2014, pending program rule making by the CPUC. SB 43 will enact the Green Tariff Shared Renewables Program, which will require a participating utility to file an application with the CPUC requesting approval of a green tariff. This program enables ratepayers to participate directly in off-site electrical generation facilities that use eligible renewable energy resources and receive a credit on their utility bill.

SB 43 allows Californians to have up to 100% of their electricity supplied from off-site renewable sources. SB 43 initially requires utilities make available 600MW of generation for customers to purchase renewable bill credits. 100MW of the allocation is set aside for projects of less than 1MW in size, which is particularly applicable to CIRE projects. The 100MW of smaller generation projects are proposed to be built in areas identified as having significant environmental and income disadvantages. Utilities will solicit bids from third party generation suppliers who will then build and operate the plants, selling the utility the clean power via a PPA.

Another important piece of SB 43 is that non-participating customers are not affected by the tariff financially. The tariff subscription price includes compensation to the utility for grid use. Any increased transmission and distribution costs are not distributed to other ratepayers who may not be participating in shared renewables investments.

4.4 Ancillary Market Participation

When a CIRE project installs a fast-acting energy storage device to manage the variability of the renewable resources, this energy storage device can access an income stream by participating in the ancillary service market.

CAISO and PJM Interconnection LLC (PJM) have become the first two regional electricity markets in the United States to propose new rules in compliance with FERC Order 755, which mandates pay-for-performance compensation for resources providing frequency regulation.

System frequency is a continuously changing variable that is determined and controlled by the real-time balance between system demand and total generation. If demand is greater than generation, the frequency falls, while if generation is greater than demand, the frequency rises.

CAISO must manage this frequency, which is becoming increasingly difficult as California increases its supply of intermittent renewable resources. One method of providing this frequency response is to integrate energy storage into CIRE projects, and actively control that storage, charging and discharging a series of batteries (in aggregation) to maintain California's grid frequency. Energy storage used in this manner also provides stability at the distribution system level and provides several distribution benefits such as:

- voltage support
- load following
- congestion relief
- regulation

In order for a CIRE project to participate in ancillary services markets in California, the device participating in the market must be on a WDT interconnection under FERC regulation. Should the CIRE project contain eligible Rule 21 DG, at the current time it is not possible to have a single interconnection for the CIRE system; separate interconnections are required for the generation and storage, or a purely wholesale interconnection is required. Behind the meter storage and Rule 21 DG is expected to be a technology pairing set to grow in California. This is in particular response to the CAISO frequency regulation market and California's mandated energy storage targets. IOU's are currently investigating how they would permit such an arrangement to operate under a single interconnection. It is likely that metering and contractual arrangements will be developed to allow storage to participate in frequency regulation markets while maintaining retail Rule 21 generation on the same, single interconnection.

4.5 Electricity Rates

There are three main rate structures applicable to CIRE projects:

- retail rates
- direct access rates
- wholesale rates

4.5.1 Retail Rates

There are two primary types of retail rates paid by California customers — rates for typical customers and rates for customers who are enrolled in the state's low-income assistance program, California Alternate Rates for Energy (CARE).

The rate structure in California has a relatively simple system for residential electric rates. There is a discounted price for a specified baseline quantity of electricity and a higher price for all electricity beyond that level. The baseline electricity use is a minimum level of usage that is intended to satisfy a substantial portion of the energy needs of the average customer in a specific service area. In response to California's energy crisis in 2001, the CPUC enacted a rate freeze for the baseline energy usage and these conditions still exist today.

An implication of this approach is that any utility rate increases (say, for grid improvements) are applied to the higher energy use tiers, penalizing those who use more-than-average amounts of energy. This gives higher energy users a disproportionately larger burden of paying for grid improvements.

Retail customers who install solar, wind, biogas, and fuel cell generation facilities via Rule 21 to serve all or a portion of on-site electricity needs are eligible for the state's net metering program. The NEM credit is used to offset the customer's electricity bill at the full retail rate, and offsets the highest priced tiers of electric usage first. NEM provides a long-term, predictable benefit tied to market value (bundled retail rates) for the customer, improving the financial viability of DG investments, particularly for higher-than-average electricity users.

This retail rate applied to the NEM generation is significantly more incentive than would be provided by exported energy if valued at the utility avoided cost rate (such as wholesale interconnections). NEM rates are typically available for the life of the system. Utility companies argue that net metering, without any charges[7] for transmission and distribution, or a fixed monthly charge, places the costs of the balance of the generation, transmission, and distribution system on the customers who don't have renewable energy. This is countered with the argument that while net-metered solar and other renewable distributed generation projects do not pay for essentially using the grid as a battery, the benefits of DG , as outlined in Section 1.3are shared by all ratepayers.

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[7] Interconnection fees are still payable as discussed in Section 3.4

4.5.2 Direct Access Rates

IOU customers in California pay a bundled rate that has two primary components: the generation charge and the transmission and distribution charge, both of which are individually displayed on an electricity bill. The bundled rate also includes other charges such as public purpose programs and nuclear decommissioning. Direct access customers also pay an unbundled rate where the generation charge is set by a contract with their Energy Service Providers (ESP), while the local distribution utility is compensated for transmission and distribution. The direct access program was closed to new customers following the California energy crisis in 2001. In 2009 the CPUC ruled that there would be a partial reopening of the direct access market, with very limited capacity. Residential customers are not eligible for the limited direct access reopening.

A customer applies for direct access energy via submitting a notice of intent during an open enrollment window in a lottery format. A customer with an accepted application will be switched to direct access as soon as possible, provided that the annual cap is not reached.

The CPUC has placed a cap of 24,792 gigawatt hours (GWh) of electricity that can be provided by direct access providers. The final allocation of direct access for 2013 was filled within 45 seconds of the application window opening (Prabhakaran, 2012). The 2013 application window was the final application window in the CPUC ruling, and it is not known if there are to be any more direct access windows.

Direct access has a limited impact on CIRE projects. The main impact of direct access would be if the direct access provider did not have a NEM tariff or other renewable energy export arrangement. Some direct access providers provide renewable energy supply options, including 100% renewable options. Direct access providers could provide a CIRE product offering and tariff to their existing customers, though none are known to do so at this time. A community member with a direct access agreement could also approach their provider or another provider to negotiate their energy supply and request CIRE-based generation, subject to contractual terms and conditions.

4.5.3 Wholesale Rates

CIRE projects will generally fall into the retail category; however, there may be instances when a CIRE project is governed by a wholesale tariff.

A CIRE project would use wholesale rates under the following circumstances:

- wholesale DG (e.g., for sale to a CCA or a utility via a PPA);
- ancillary services market participation.

The type of interconnection that governs CIRE projects will also govern their rate structure. A CIRE project that connects under a wholesale agreement will receive a wholesale price for their generation or market participation service. Wholesale rates are not compatible with retail rates and as such cannot offset retail rates of a customer's site. This may lead to a reduction on the economic performance of a CIRE project as CIRE projects do not have the economies of scale that large utility scale wholesale generation projects have.

4.6 AB 327: Net Metering and Residential Rate Reform

The recently approved AB 327 paves the way for rate reform in California and affects retail rates as well as the NEM program and availability, both important for CIRE projects.

The bill does not itself make any changes to residential electric rates, but removes the rate freeze restrictions in existing law that limit the CPUC's ability to consider proposals to adopt differing rate structures for the baseline energy consumption bands. Effectively, this would enable IOUs to propose higher tier 1 and 2 tariffs, and thereby reduce tier 3-5 tariffs, leveling the rate structure somewhat. No changes in electric rates can be adopted until full hearings and public consultations take place in open proceedings at the CPUC.

AB 327 is applicable to CIRE projects for the following reasons:

- It allows the potential for retail rate reform in California.
- Ensures that NEM will remain in place until the IOU's have installed at least 5,200MW on NEM generation. Under the existing rules NEM could have been suspended by the CPUC as early as the end of 2014.
- Under existing regulations there was a NEM cap that was statutory; AB 327 provides a path forward for the CPUC to begin the process of removing that net metering cap. The existing cap is set at 5% of utility non-coincident peak load, beyond which new solar customers were no longer guaranteed to receive net metering credits.
- The CPUC previously could not order utilities to procure any renewable energy beyond the 33% RPS; AB 327 removes that ceiling, effectively creating an uncapped RPS.
- Permits the CPUC to develop a new NEM tariff for future NEM projects taking service beginning July 1, 2017 or when the IOU reaches an existing statutory cap on eligible renewable projects.
- Permits the CPUC to approve up to a $10 fixed charge on residential solar customers.

4.7 Feed-in-Tariff

Renewable Feed-in Tariffs (FITs) offer long-term wholesale electric energy contracts to eligible generators. In California, the FIT is termed a Renewable Market Adjusting Tariff (ReMAT).

California has a target of 750MW of renewable generation to be installed under a FIT and the eligible project size is a maximum of 3MW. The three Californian IOU's were appointed approximately 500MW of this target with the remaining allocation going to the municipalities. ReMAT offers 10-, 15-, or 20-year PPAs for wholesale power generated from eligible projects. Requests for the ReMAT began on October 1, 2013, and the first ReMAT program period began on November 1, 2013.

There are three product types within the ReMAT: As-Available Peaking, As-Available Non-Peaking, and Baseload and the contract price for all three product types began at approximately $89/MWh. The contract price for each product type will adjust independently, based on market rates.

The second pricing period launched on January 2, 2014 with a price of $89.23/MWh for the Baseload Product Type and for the As-Available Non-Peaking Product Type. The price for the As-Available Peaking Product type was $85.23/MWh.

The ReMAT is applicable to CIRE projects for the following reasons:

- Offers a long term contract to finance a CIRE project
- Is aimed at community scale projects of up to 3MW (AC) in size
- Increases the value of the generated energy when compared to standard wholesale tariffs

4.8 SB 594: NEM Aggregation

SB 594 (Net Energy Metering Aggregation) is a Senate bill that was signed into law and approved by the CPUC in September 2012. SB 594 is expected to be fully implemented by the three Californian IOUs in the first quarter of 2014.

SB 594 will allow all NEM customers with multiple electrical accounts to aggregate the electrical load of all the meters located on the property where their renewable energy system is located, or on property contiguous to the renewable system. Meters on contiguous properties must be solely owned, leased, or rented by the eligible customer-generator to be included. Parcels divided by a street, highway, or public thoroughfare are considered contiguous provided that they are otherwise contiguous and under the same ownership.

SB 594 will allow a customer to install one renewable energy facility sized to serve their entire on-site load (up to 1MW) instead of installing separate facilities at each meter.

SB 594 is applicable to CIRE projects for the following reasons:

- Allows a customer to increase the scale of multiple building generators to community scale
- Allows the use of the utility distribution system to allow the generation to be shared

4.9 Virtual Net Metering

Multi-tenant buildings with individual electric meters for each tenant cannot easily install distributed solar PV systems because of the difficulty of assigning the benefits of the generation to each occupant.

Virtual Net Metering (VNM) is the process of allowing participants to install a single solar system to cover the electricity load of a multi-tenant building. The electricity is not individually connected and portioned to each meter. Rather the generated energy feeds into the general building distribution system and then each participating resident is allocated the credits 'virtually' to their meter.

The first VNM rate structure in California was the Multifamily Affordable Solar Housing (MASH) program. The MASH program is designed to subsidize PV systems in multifamily housing which will offset electricity loads. The MASH VNM rate schedule allows MASH program participants to apply the credits from a single solar system to multiple accounts at an eligible low income building as defined in Public Utilities Code 2852.

Based upon the merits of the MASH program and wider pilots, the CPUC authorized the expansion of VNM to the general multi-tenant market in Decision (D.)11-07-031. VNM is now available to all eligible multi-tenant buildings in California.

Virtual Net metering is applicable to CIRE projects for the following reasons:

- Allows a building owner to install a community scale energy system to provide clean energy to the common areas and residents of a multi-tenant building.
- Allows tenants to receive renewable energy which is installed directly at the load center.

CHAPTER 5: Regulatory Framework Observations

The existing regulatory framework does not allow all CIRE projects to be fully implemented in California. CIRE projects allow community members to share DG that is installed within the community and transmit the generated electricity to the community members directly.

Important steps have been taken to reduce CIRE barriers and there are many legislative policies that have been implemented to break down barriers as described in Chapter 4.

One impediment to CIRE project implementation is the barriers to entry for both utility and private developer ownership of projects, which include the following:

- the need to become a regulated utility when distributing energy to more than two community members
- incumbent utility business models
- the existing electricity rate structure
- the ownership of generation and distribution assets

CIRE projects that involve the sale of energy to more than two customers or changes to the existing way in which electricity rates are determined will require changes to the current regulatory framework. As stated in Chapter 4, the existing regulatory framework, except in certain ownership cases, prohibits the sharing of energy between buildings in most scenarios. The regulations also prevent the construction of private wire facilities in a franchised utility territory.

Regulation in California has resulted in utilities employing a cost-for-service business model. In a cost-for-service model a utility will spend capital to build an asset and is permitted to make a reasonable return on that asset. Regulators assess the need for the utility to build the asset in the first place and determine a reasonable return on investment. This form of regulation does not incentivize utilities to develop different business models, nor to promote CIRE models that don't include IOU ownership of assets. An ideal regulatory framework would allow the utilities to be compensated fairly for the service that they provide while also incenting them to achieve the state's broader goals. These broader goals include reducing the reliance on fossil fuels, upgrading the grid infrastructure, limiting environmental impacts, providing customer satisfaction, a reliable network, and affordable energy.

The CPUC has already made great strides in rewarding utilities to sell less energy in the form of its efficiency incentives. The incentive mechanism financially rewards utilities for maximizing long term energy savings, such as helping customers improve the efficiency of their entire home. Rooftop solar behaves similarly to an efficiency gain in that less electricity is procured from the utility and replicating the successful efficiency program to include generation would result in more CIRE projects in California.

In California energy use has been declining, due in part to aggressive energy efficiency standards as well as DG. Falling volumetric sales do not impact utility earnings, but may result in higher rates to other customers who do not take advantage of the energy efficiency or DG programs.

The existing electricity rate structure is a challenge for both consumers and utilities alike. The cost of renewable generation has been falling year on year. As generation costs continue to fall (particularly PV), DG is expected to ultimately reach grid parity in terms of cost per kWh that an individual utility customer pays .There is a risk that under the current rate structure, increased DG could affect customers and utilities. As more customers chose to supply their own power due to falling generation costs or "rent a roof"[8] schemes, the costs of maintaining the distribution grid, regulated profits and important public purpose programs (e.g., energy efficiency incentives and low income discounts) falls on a smaller pool of volumetric sales. This causes the utility rates to increase. A risk of this increasing rate scenario is that more customers choose to generate their own electricity, further reducing the pool of customers and driving costs and rates higher.

Another important consideration when assessing the viability of CIRE models is the responsibility for ownership and operation of DG. Currently, behind-the-meter PV is generally installed by either private home/business owners or third-party generation suppliers; IOUs (as part of their regulated business) do not install DG in customers' properties. Whoever owns the generation maintains and operates the generation and is responsible for the performance of the asset. A CIRE model calls for generation to be shared between multiple customers, so it will require new frameworks of ownership and operation. If a CIRE generator is to be responsible for providing a forecasted kWh of energy, the new framework must consider the consequences if the generator falls short and the responsibilities for making up the shortfall and at what cost.

[8] With a "rent a roof" scheme a third party solar installer will install and maintain a solar installation on a customer's house for no cost down. The customer will have a reduced utility bill, but not own the system. The customer will be locked into a contract to host the solar installation for a minimum fixed period.

CHAPTER 6:
Market Need

In order to determine whether further research and potential legislature changes are required to facilitate CIRE projects, it is important to understand the market for CIRE projects. As part of this CIRE study, the project team is holding a series of workshops and one of the questions posed to the project participants is about market need. The results from the workshops will be included within the Task 3 Report; an updated version of the Task 2 report will also be issued in November 2014, which will include the workshop results.

In advance of our targeted local questions, we have used the following methods to determine a market need for CIRE projects:

1. existing public research
2. utility industry research

6.1 Public Research

While there is no definitive research into CIRE projects and models, there are several indicators that can be used to determine whether citizens are in favor of renewable energy, where they prefer it to be sited, and their willingness to pay more for this energy.

Once such survey was commissioned by The Swiss Reinsurance Company Ltd (SwissRe) in their risk perception survey.

The perception survey was carried out in April and May 2013 by The Gallup Organization – Europe.

The survey asked a series of 54 questions in 5 category areas:

- Overall risk
- Funding longer lives
- Managing climate and natural disaster risk
- Advancing sustainable energy solutions
- Partnering for food security

For this report we reviewed the advancing sustainable energy solutions questions, of which 11 questions were asked out of the total of 54.

The survey results are based on telephone and online interviews with more than 1 000 adults per country, aged 15 and older. The samples are representative of the total adult population in most countries; in five countries, interviews were only conducted in urban areas. The 19 markets selected for the Swiss Re study were:

- Canada, the United States, Brazil (only urban areas) and Mexico
- France, Germany, Italy, the Netherlands, Switzerland, the United Kingdom and South Africa (only urban areas)
- Australia, China (only urban areas), Hong Kong, India (only urban areas), Indonesia (only urban areas), Japan, Singapore and South Korea

For this report, we narrowed the data to US citizens and reviewed four key questions from this research. The questions do not indicate preferences at a state level but point to a broad cross section of the American public. The questions selected allow conclusions to be drawn about the market need for CIRE projects and who should own and operate them.

All results were obtained from Swiss Re Risk Website[9]

6.1.1 Question 1

"If your electric/utility company would provide renewable power, would you be willing to switch to renewable power?"

Table 2: Swiss Re Risk Study Question 1 Results, United States

Number	Answer	Result (%)
1	Yes, I am already using renewable power in my home	9.40
2	Yes, I would consider using renewable power in my home	62.30
3	No, I am not willing to use renewable power in my home	12.40
4	Don't know / No answer	15.90

[9] http://riskwindow.swissre.com

6.1.2 Question 2

"If you would be willing to switch to renewable power, are you also willing to pay extra for it?"

Table 3: Swiss Re Risk Study Question 2 Results, United States

Number	Answer	Result (%)
1	Yes	32.20
2	No, I cannot afford to pay more than I do now	52.00
3	No, I can afford to pay more, but am not willing to do so	11.80
4	Don't know / No answer	4.00

6.1.3 Question 3

"If you are willing to pay extra for renewable power, how much extra?"

Table 4: Swiss Re Risk Study Question 3 Results, United States

Number	Answer	Result (%)
1	Up to 5% extra on my monthly energy bill	43.90
2	Up to 10% extra on my monthly energy bill	39.11
3	Up to 15% extra on my monthly energy bill	8.30
4	More than 15% extra on my monthly energy bill	5.11
5	Don't know / No answer	3.70

6.1.4 Question 4

"Would you be willing to install equipment to generate renewable power yourself in your home, e.g. solar panel, heat pumps or a wind turbine?"

Table 5: Swiss Re Risk Study Question 4 Results, United States

Number	Answer	Result (%)
1	Yes, I already have such equipment	5.50
2	Yes, I would consider installing such equipment	43.60
3	No, I would not consider this, because it would be too expensive	26.40
4	No, I would not consider this for other reasons	13.10
5	Don't know / No answer	11.30

6.2 Utility Research

The Edison Electric Institute (EEI) is an association of US shareholder-owned electric utilities. EEI members serve 95% of the ultimate customers in IOUs and represent approximately 70% of the US electric power industry. The three Californian IOUs are all members of the EEI.

In January 2013 the EEI issued a report titled *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*. The report discusses the technological and economic changes that are expected to affect the electric utility industry, detailing at length the effect that DG is having on the utility business and examining the future scenarios where more DG may come online and concluding that new models are necessary within the utility industry.

The report states that current policies have concentrated the majority of DG behind the meter to 10 utility areas, including the California IOUs. Nearly 25% of renewable behind-the-meter generation is installed in PG&E's territory. It also predicts further growth in DG, noting that by 2020 distributed resources will account for 10% of the electric capacity in key markets such as California. The EEI goes on to calculate the economic impact of such distributed energy growth. The report estimates that if DG customers increase to 10% of capacity and are compensated for this generation at the current level, the average base electricity prices for nonparticipants of DG will increase by 20%.

6.3 Summary

US citizens clearly have a desire for renewable power, and based on the Swiss Re research, customers have a slight preference for their utilities to provide this renewable power (62%). Over half of respondents either already had renewable power or would be willing to install the power on their individual homes, while 26% would not install the renewable power on their homes as they deem renewable energy as too expensive.

Of those who preferred that a utility to provide the renewable energy, 32% would pay extra for the renewable power. Almost half of those willing to pay for renewable power were willing to pay 5% extra (44%), while 40% were willing to pay 10% extra. There is a steep drop-off for paying any more than a 10% premium for renewable energy.

Costs are clearly a very important factor for the American public when determining renewable choice. A CIRE project — a centralized, shared, and economic generation source — has the potential to maximize the number of people who move to renewable energy by potentially reducing individual homeowner costs, depending on the scale, location and associated transactional cost. The EEI report clearly identifies DG as a growth electric generation source with the potential to be a disruptive challenge to the utility industry. The Swiss Re report confirms the market need and introduces an opportunity for utilities, which is discussed in Chapter 8 of this report.

CHAPTER 7: CIRE MODELS

7.1 Overview

This chapter defines four CIRE models and describes the issues that each model encounters in California under the current regulatory regime. The first model is presented in this report to detail what is possible within the current regulatory framework and community energy. The model is not a true CIRE model in that it does not describe an integrated, connected community energy system. Models 2 through 4 are innovative CIRE models that are subject to regulatory challenges.

All of the CIRE models within this report have investigated the generation, distribution and sale of electricity only. A CIRE project may challenge the traditional electricity network business model and will likely cause tensions between IOUs, regulators, developers, and rate payers.

The CIRE models in this chapter are organized in the following way:

- Description of the model
- Challenges to the model
- Potential mitigating solutions

This phase of work has included outreach to these interested parties to document common interest with the aim of highlighting areas of policy that may be changed to the satisfaction of all parties. Table 6 provides a summary of the CIRE models.

Table 6: CIRE Model Summary

CIRE Model	Name	Description	True CIRE Model	Regulatory Barriers
1	Offsite Generation	Members of a community who have no space for renewable energy but who want renewable energy to supply their individual property/business	No	No
2	Single Owner Campus	A single community member who wants to install renewable generation at their multi parcel campus.	Yes	Yes
3	Multi-Owner Community	Community members within a contiguous or multi parcel boundary whose energy is provided by centralized, co-located energy generation	Yes	Yes
4	Microgrid	Community members spreading over multiple land parcels whose energy is provided by centralized energy generation and have the ability to separate from the wider grid and operate independently (microgrid)	Yes	Yes

7.2 Model 1 – Offsite Generation

Members of a community who have no space for renewable energy but who want renewable energy to supply their individual property/business.

7.2.1 Model Description

Approximately 75% of Californians cannot install renewable generation on their property or business (*Denholm, 2008*). This may be due to a variety of reasons such as lack of space, lack of access to a renewable resource, a tenant within a building, or lack of upfront capital or financial credit.

This CIRE model does not focus on an interconnected community. This CIRE model applies to any individual members of a community, who may or may not be physically adjacent to each other, or to a renewable generating asset, but who have a desire to supplement their electricity with up to 100% renewable energy. The community member would like to purchase this energy from a provider of this renewable generation and have this credit applied to their energy bill. The community member and the generator do not have to be in the same neighborhood.

7.2.2 Model Regulatory Challenges

The passing of SB 43 has created a regulatory path forward for this model. SB 43 allows Californians to have up to 100% of their electricity supplied from renewable sources through off-site sources. SB 43 will make it possible that there is renewable generation available for a customer who wants to subscribe for it (within a 600MW allocation). The utilities will contract the services of wholesale generators to procure eligible generation. This generation is virtually applied to the meter of the community member who signs up for the rate with their local utility, although participating customers continue to pay all appropriate costs required to supply this electricity.

While SB 43 provides a pathway for individuals to obtain clean power, it does not present a community wide solution. It also does not allow third parties to develop community energy systems and sell and distribute that energy to community members. Model 3 describes in detail these challenges and opportunities.

7.3 Model 2 – Single Owner Campus

Model 2 applies to single owner communities where one owner owns all of the buildings that are being considered as part of the CIRE project, even if they are not contiguous.

7.3.1 Model Description

This CIRE model is a community that is not contained on one contiguous land parcel. There is one owner of the community, for example, a large corporation/business, a hospital, or a university. There are many such communities all over California. A number of companies have seen organic growth of their corporate campuses, which are often intermingled with public streets and served by utility infrastructure.

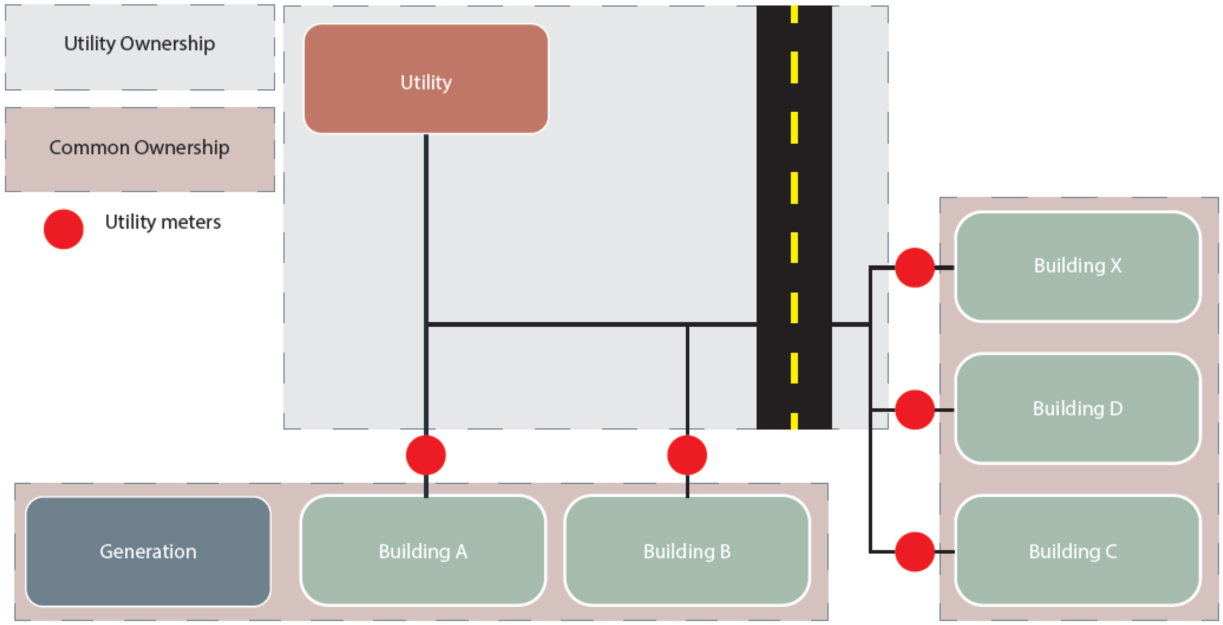
The non-contiguous community has many buildings. The campus owner has potential plans for expansion either by acquisition of existing local buildings or the construction of new buildings. All of the buildings typically have an individual utility connection, and the utilities distribution system distributes power to each building.

Each building has the opportunity for renewable generation to be installed local to the building, however constructing a renewable generator to provide power to all buildings in a single generator would allow the owner to maximize the generation and/or system efficiency to suit the demand of the buildings, for example by installing an electricity generating fuel cell.

A key feature of this CIRE model is that the community has a single ownership.

Within this CIRE model there is a strong desire to reduce the energy consumption via a mix of energy efficiency and on-site renewable generation to move towards a net zero energy use.

Figure 5: CIRE MODEL 2



7.3.2 Model Regulatory Challenges

Initial regulatory review has raised the following immediate questions:

- Are building owners allowed to distribute electricity to other parts of their own campus?
- How can the existing utility enable this CIRE model and receive fair compensation

The buildings are owned by a single organization and the owner wants only to offset their campus load with a centralized generation source. The organization does not want to sell energy to any other customer and wants to use all of the generation energy for their loads.

Each individual building has a separate electricity meter and the only interconnection between the buildings is via the existing utility's distribution system. The private organization does not control any of the distribution between the buildings and has no method of physically connecting the buildings except by the utility distribution system.

By the above definition, all of the organization's buildings within this hypothetical CIRE project would remain utility customers. Each customer meter would have an individual utility account and would pay the utility for the electricity provided to them. The organization would be billed individually per building.

The customer in this scenario would like to centralize generation and provide this power to all of their buildings. Two options regarding this scenario are discussed below:

- Installing a private wire system
- Wheeling[10] power

The company's buildings are dispersed and separated by public rights of way. To install a private wire system and operate the campus from one large utility interconnection[11] is not possible with the current regulatory framework. The issue that compounds the feasibility of installing a private wire system in the CIRE district is electrical franchise rights. Local cities generally grant utilities exclusive[12] franchise rights to 'lay wires in the ground' in the franchise area. In the above CIRE model installing a private wire system to supply multiple buildings would require a local franchise agreement. There is some flexibility in the current framework. If the campus is only defined as non-contiguous as it was separated by a single public right of way, then a private wire is likely to be acceptable to provide generation to the single building that is separated by a public right of way. In this case, the majority of the campus would be required to be on a single contiguous land parcel with a single interconnection with the existing utility.

In this CIRE example each building is a retail electricity rate customer. Generation and buildings are all interconnected and billed/credited at retail rates. Centralized generation is likely to be a mixture of NEM and non-NEM depending on the size of the campus development. Power 'wheeling' would allow the campus owner to generate access energy at a central location and apply this generation to buildings A through X either via an energy sale to itself or via some form of bill credit. In California there is no current mechanism for power wheeling to occur for retail customers.

7.3.3 Potential mitigating solutions

There are two potential solutions to this CIRE model. The first potential solution for this scenario is contained within the implementation of SB 546. Known as "aggregated NEM," SB 546 allows NEM generation to be shared across a customer's properties through virtual net metering. A significant limitation of the aggregated NEM for this application is likely to lie in the maximum rating of the generator which has been set at 1MW. SB 546 was written primarily to allow farmers a greater opportunity to provide economical NEM installations at their farms. Farmers often have irrigation pumps on their land boundary separately metered from a main supply. The passing of SB 546 allows these farms to install a larger solar array on their main meter to offset the pumping assets on separate meters.

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[10] Wheeling refers to the transfer of electrical power through transmission and distribution lines. In the case of a CIRE project we mean company 'A' sells power to itself using the existing utilities distribution assets to do so.

[11] Subject to the load of the buildings and interconnection capacities

[12] Not all cities grant exclusive franchise rights. For example in San Francisco, which is in PG&E's service territory, there is a municipal utility SFPUC which is authorized to construct distribution assets.

The second potential solution for the regulatory barriers to this CIRE model has a precedent in a non-California IOU territory. An IOU could develop a rate that allows the owner of the campus to install a generation asset large enough to provide power for all of the individual buildings, but install this generation centralized to campus at a location that suits the campus; say one of their buildings with the required land available. The campus owner then uses the existing IOU infrastructure to distribute this generation to the other buildings while the IOU receives revenue for allowing the use of its infrastructure and billing mechanisms to net the generation via VNM.

Like many IOUs, New York's Consolidated Edison Company (Con Edison) is forecasting significant future DG on its networks. Con Edison estimates that its connected generation is going to increase from 150MW in 2012 to a base case of 500MW in 2030, an increase of over 333% in a little over 15 years. Con Edison has designed a new tariff[13] that allows it to receive compensation for facilitating the sharing of renewable generation in single-owner-campus-type settings. The remainder of this section provides details of the Con Edison proposed electric rate tariff.

The utility allows larger generators (between 2MW and 20MW) to be installed by the organization, connected to their local distribution network. The utility's wires are then used to distribute the generator's output and the generation is credited to all of the customer's meters. The utility then makes a fair charge for the use of their distribution assets. In essence the campus customer can install larger centralized generation and use this generation at all of their existing buildings and the utility gets fair compensation for allowing the use of their distribution assets.

The Con Edison existing generator tariff is similar to the Rule 21 connections that are currently in operation in California, both tariffs have the following features described in this paragraph. DG can be connected to each particular customer account, and the DG can be used to offset load at that meter/account. The generator may export to the IOU, and the IOU will compensate the generator for the generation in the form of a bill credit or some other method depending on the arrangement of the individual generator. If the customer has multiple buildings, each must have local generation — generation cannot be generated in one building and "wheeled" to other buildings.

The new Con Edison electric tariff allows customers that have utility service accounts at multiple buildings that may be on more than one parcel of land to centralize their generation at one site. The kW export of the generating facility should not exceed the aggregated load of all of the buildings whose load is to be offset by the generating facility.

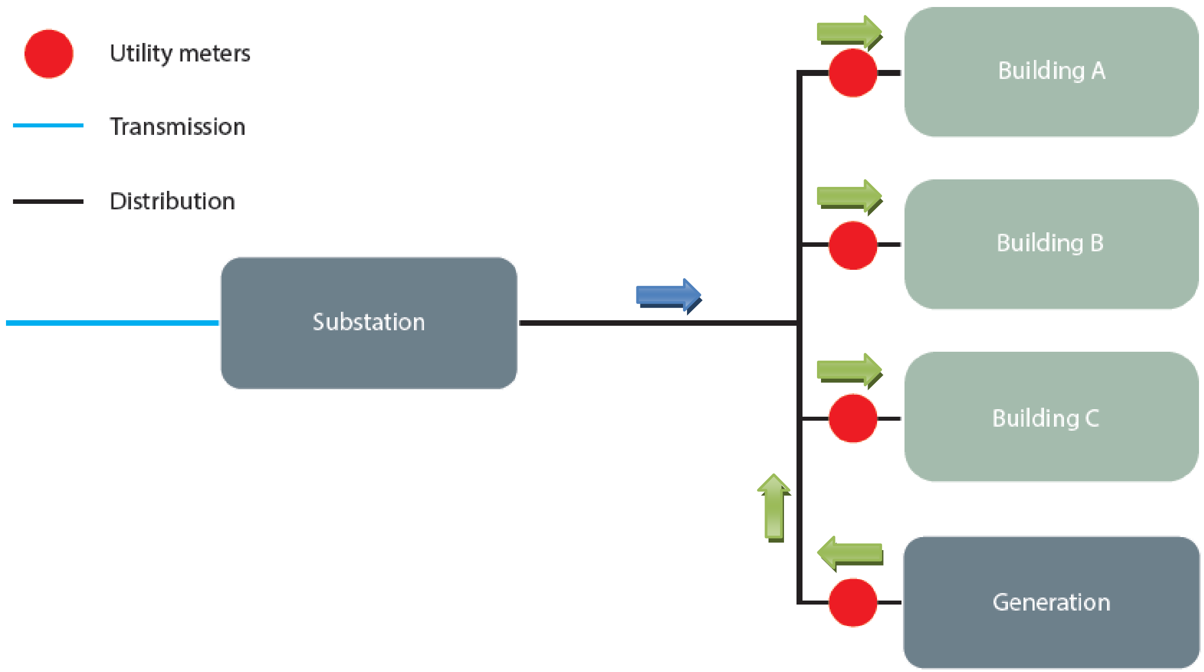
The customer is responsible for installing and maintaining all metering and communications. The method of communications for large campuses separated by public streets would need consideration, but a tariff such as this in California is likely to encourage campus-type premises

13 https://www2.dps.ny.gov/ETS/search/searchSubmissionID.cfm?sub_id=2767019

to investigate the feasibility of centralizing generation to provide energy to all of their buildings from a central generation source.

An example of how this may be connected is shown in Figure 6.

Figure 6 New Rate Structure Schematic



Further details of the Con Edison tariff proposals, including the submission to the Public Utilities Commission, can be found at the below web references.

http://www.coned.com/dg/faq.asp

https://www2.dps.ny.gov/ETS/search/searchSubmissionID.cfm?sub_id=2767019

7.4 Model 3 - Multi-Owner Community

Model 3 applies to communities with multiple property owners and utility customers within a contiguous (i.e. not separated by any public right-of-way) or multi -parcel boundary whose energy is provided by centralized energy generation. Community members are individuals and/or organizations and may be a mix of property owners and tenants.

7.4.1 Model Description

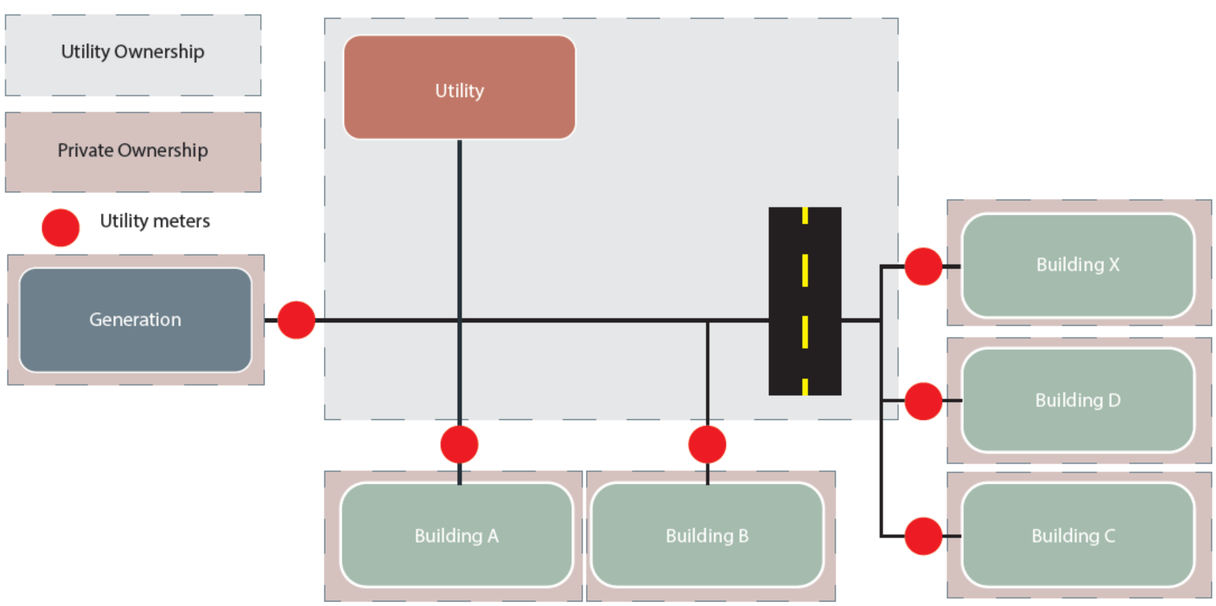
This model may be a designated eco-district, a large new development, an existing block or the redevelopment of a city block such as is common in Central SoMa. The community may be made up of a mix of commercial and residential properties and a mix of building ownership and leases.

The CIRE project would involve installing a centralized generation plant. The community members would share this centralized generation with all community members in the project area. The community members may benefit from the centralized generation by reduced energy bills, greater local control or choice over type of energy supply (particularly renewable). With right sized generation, the community could become a net zero energy community.

The multi-owner community has two ownership models and we will discuss the challenges each of these faces within this Section.

The first ownership model is a private ownership model and this is shown below:

Figure 7: CIRE MODEL 3 – Private Ownership



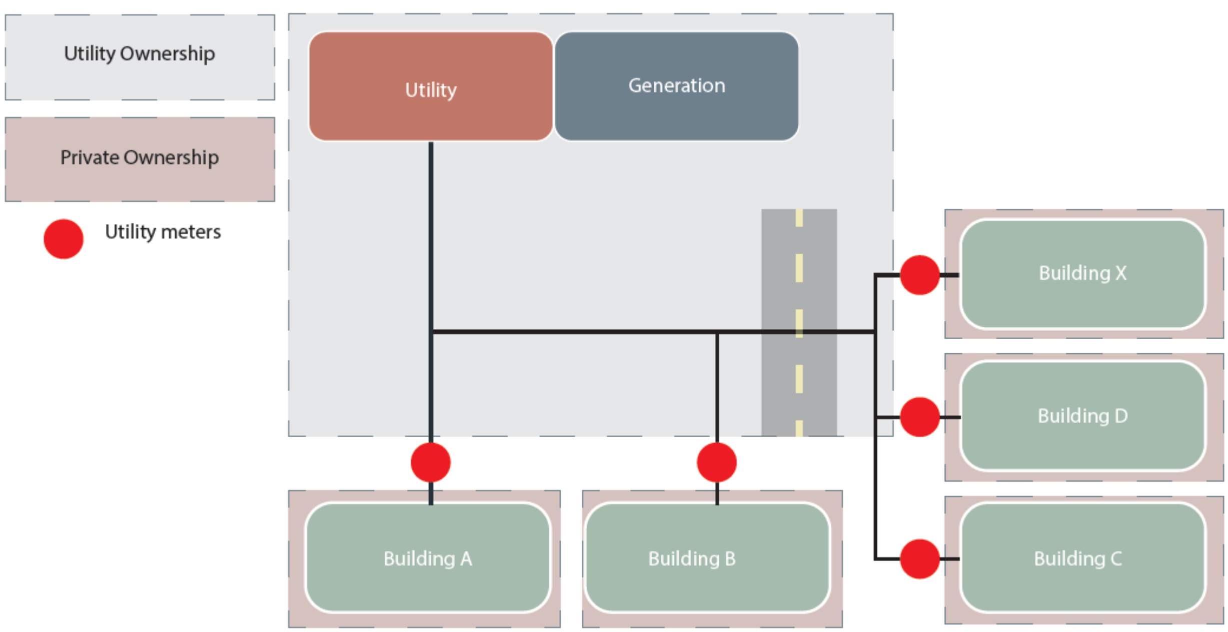
In an existing or new community, each of the community members would typically be IOU customers[14]. Each customer would have an individual meter and electricity account. The buildings are all owned by differing individuals. The centralized generation would be privately owned. The community members could form a co-op and own the generation asset, a developer could own the asset, or the assets could be owned by a third party.

An alternative would be to install a private wire system to supply all of the buildings within the development and have a single meter for the complete community. Here it would be assumed that some entity owns the private wire system and distribution and connects directly to the utility as a point of common coupling.

The system has no ability to operate independently from the grid as a microgrid. The generation is always connected at the distributed level and sized to ensure that over a defined period, such as a month, the generation output will match the load.

The second ownership model is a IOU ownership model and this is shown below:

Figure 8: CIRE MODEL 3 – Utility Ownership



[14] In San Francisco, some new residential community developments (Hunter Point and Treasure Island) shall have their electricity provided by the local municipal utility San Francisco Public Utilities Comission (SFPUC). With this ownership model there are multiple opportunities for CIRE projects and a future revision of this report will include municipal utility models.

Within this model, the local utility owns and operates the complete CIRE system. A utility, in response to the market demand of a community, developer or other business needs, develops a CIRE system under the ownership of the utility.

The generation may be installed centrally and sized to feed all customers in a community or the generation may be installed on the customer's property, behind the customer's meter. Within the CIRE area the generation is sized so that over the course of a defined period, such as a month, all of the generation output matches the load of the customers. The utility then sells customers this clean, local power to cover all of the communities electricity needs.

7.4.2 Model Regulatory Challenges

This model raises many technical, economic, ownership, and regulatory issues.

We will first discuss the issues pertaining to a project developer/ third party owning and operating the generation assets and secondly the local utility owning the CIRE generator.

7.4.2.1 Community, Developer, or Third Party-Owned System

This section is written under the premise that most real estate developers have no desire to become a regulated utility or electric corporation.[15]

Initial regulatory review has raised the following immediate regulatory questions:

- Are non-regulated utilities allowed to sell energy to other community members?
- Can the distribution network be a private wire system?

On the whole, retail sales of electricity in California can be provided in one of two ways:

1. by the local utility (IOU or other)
2. by a "direct access" ESP

Electric utilities have a defined geographic service area and are required by California law to serve customers in that area. There are exceptions for direct access accounts (as described in Chapter 4 of this report and other.

It is unlawful within the current regulatory framework for a non-regulated private utility to sell retail energy in an IOU's territory. If we take the definitions of electricity sale from the CPUC regulations it is concluded that you are an electric corporation if you sell electricity. Provided a listed generation source is used for the generation, there are exclusions to becoming a regulated utility, however , these regulations all have the qualifier that you can sell to no more than two adjoining properties and that they cannot be bounded by a public right-of-way. This regulation in theory can be used to sell electricity to two adjacent properties (two metered accounts only) in this CIRE model. This would perhaps provide some meaningful contribution to the 12,000MW goal if the two additional metered accounts were large industrial users.

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[15] A future work stream in this project will interview developers and owners to determine this.

The second issue that compounds the feasibility of installing a private wire system in the CIRE district is electrical franchise rights, as defined in Model 2. In the above CIRE model installing a private wire system to supply multiple residents would require a local franchise agreement if a public right of way was crossed.

Within the hypothetical CIRE scenario, the role of the utility with the current business model is severely compromised. Utilities are permitted to make a reasonable return on investment by transmitting electricity to customers and receiving revenue. Should this CIRE development become a net zero development (yet still require the assurance of power should intermittent generation not be generating) the existing utility business model does not allow for the utility to be adequately compensated for the service that they provide.

There is one regulatory regime in which a CIRE project as modeled in this scenario is feasible: A community choice aggregator (which can only be a city, or country or other public agency) can set up a community choice aggregation scheme taking on the electric supply responsibility to all customers within the jurisdiction of the local agency who do not opt-out. Here the CCA is responsible for contracting generation services and can provide this generation supply from local renewable sources, sited within the development.

In conclusion, under the current regulatory framework and with the exception of CCA, this model of CIRE project is not feasible for projects that service more than two adjoining properties to the property where the generation is located

7.4.2.2 Utility-Owned System

Initial regulatory review has raised the following immediate regulatory challenges:

- The requirement of CPUC approval to own and operate new generation assets
- How are generation assets priced?
- Limitation of existing rate structure to charge utility customers differing rates

A first inspection, this model would seem to fulfill many of the needs of CIRE customers. It would allow centralized generation and it places the generation assets into the hands of an experienced, existing provider. A utility[16] has all of the billing mechanisms set up, has access to each individual customer, can accurately calculate billing credits and can directly credit a bill.

One regulatory hurdle to this model is the need for a specific approval from the CPUC for an IOU to own and operate generation in this scenario. The regulatory challenge is further compounded if the generation station was a cogeneration plant. Electric utilities are typically not regulated to sell thermal energy and this would require further regulatory (and business) investigations by the utilities.

[16] Future revisions of this report will also investigate non-utility energy providers with these skills such as local municipalities, third party generators and energy service providers.

The existing rate structure does not support this model, as rates are set in a standard fashion across a service territory for each customer class, with only a limited number of customer class delineations. A special CIRE rate would need to be determined and approved by the CPUC for the customers under this CIRE model and applied to CIRE customers only. IOUs would face many challenges in trying to develop location specific rates based on this model. The challenges may include:

- Introduction of more rate and customer classes
- Added rate complexity

Who should receive a special rate and how is this assessed

7.4.3 Potential Mitigating Solutions

These CIRE models describe a community that may or may not be not contained on one contiguous land parcel. There are multiple owners of the community, for example multitenant residents, stores, a community center, and small businesses. There are many such communities all over California. Some are found in existing neighborhoods, such as San Francisco's Central SoMa, which are poised for redevelopment and may be purpose-built new communities in greenfield or brownfield sites. This type of development represents the largest opportunity for CIRE projects; there are communities in every neighborhood in California that will be suitable for these CIRE models.

The community has many buildings, some existing with potential plans for expansion either by acquisition of existing buildings or the building of new buildings. All of the buildings typically have an individual utility connection, and the utilities distribution system distributes power to each building.

There is a potential solution to enable this CIRE model. The ownership and operation of the CIRE generation determines the possible solutions. Three examples have been described for enabling CIRE projects within a community and have been ordered in terms of their complexity to implement

1. utility ownership of CIRE
2. third-party ownership of CIRE
3. customer/property owner/site host ownership of CIRE projects

7.4.3.1 Utility Ownership of CIRE Projects

An IOU understands and has all of the necessary skills and processes to install, operate, meter, bill, and maintain generation assets. In California's competitive generation landscape, an IOU is permitted to purchase new generation assets. These generation assets are assessed by the CPUC and must meet certain criteria. However, CIRE projects are localized generation assets that do not serve the wider population located in an IOU's service territory and therefore will not meet the criteria set by the CPUC for determining least-cost generation assets.

San Diego Gas and Electric (SDGE) has conducted research via its sustainable communities program that was recently closed to new projects. Under the sustainable communities project, SDGE worked with customers to create showcase energy efficient, sustainable projects that incorporated SDGE owned and operated renewable generation on customers properties. SDGE connected the generation to their side of the meter and the generated electricity became wholesale power to SDGE. The customers continued to purchase power from the utility via a retail rate. The consumers who had generation installed at their property were paid a lease. A 100kW generation system would attract an annual lease payment of $1,700. The lease terms were 20 year leases with options for the customers to buy the generation asset at years 10 and 15. The SDGE trial was a success and installed over 4MW of clean generation in 40 projects. The scheme was not considered business as usual and the projects were installed during a research project with the permission of the CPUC.

The Swiss Re study discussed in Chapter 7 indicates a demonstrated preference for a utility to own and operate renewable generation assets and for that renewable energy to be sold to utility customers directly.

A utility could identify a community and install and serve that community with localized renewable generation as identified in CIRE Models 3 and 4. In order for this model to be feasible and for IOUs to move to IOU-owned distributed energy as opposed to the more common centralized generation, the CPUC rules must change. Generation would have to be assessed in terms of a broader set of criteria such as environmental good and other State objectives. The utility may directly install and operate this local generation or contract the services of an independent power producer within its own territory.

Building a CIRE project at the community level involves risks:

1. Is it feasible for a utility to get a system approved and contracted within the time scale that a private property developer is operating?
2. Would a utility need some pre-approvals within given constraints and a special office that is able to move on the issue quickly?
3. What if the client base somehow backs out over time?

A community scale project in order to be feasible requires clear, long term contracts that clearly define timescales, responsibilities and a long term take off of the generated power to a specific development.

Another method for supplying a community with renewable energy is for a utility to supply renewable energy at the individual customer level. This is a method proposed by the former US Secretary of Energy Stephen Chu. Here a utility would install behind-the-meter generation (and also potentially storage) on an individual's property. The utility would own, operate, and maintain the generation and continue to supply energy to the utility customer at a rate that makes economic sense to both the utility and customer. Here the customer has renewable energy provided at their property and receives local renewable energy. The utility has not lost this customer and continues to earn a revenue for supplying this customer as well as covering the costs for providing that customer with backup power should the renewable energy (and potential associated storage) not meet the energy needs of the customer. The utility could also invest in residential solar outside of its regulated territory, for example. This would happen much like a utility invests in larger centralized generation sources. One advantage to the utility with this solution is that the utility then has a relationship with a new customer, which may provide mutually beneficial sales opportunities.

Utilities currently own all of the distribution assets and mechanisms for recovering costs for this CIRE solution.

A utility ownership model has many advantages, and we recommend that potential policy changes be investigated in this area to fully document the required changes to allow an electric utility to own and operate CIRE projects, whether at a shared community level, the individual customer level, or a combination of the two.

Utility owned DG has the potential to reduce the utilities rate of return from the assets that are already installed to a business plan. The current structure of regulation allows the existing rate of return to be fixed and this would cause a potential rate increase for non CIRE customer. The rate design needs to take this nuance into account and be designed to ensure that non CIRE customers are not affected by the installation of CIRE projects.

7.4.3.2 Third-Party Ownership

A third-party owner installs, maintains, and operates a community generation system on behalf of the community. As detailed in Chapter 4, this is a feasible option under the current regulatory regime only if electricity is sold to two other customers or the third party is a regulated utility with franchise rights in the territory that the generation is being installed. This option is currently not possible for mass adoption due to the current regulatory framework.

The third-party owner would sign up customers in a community who want to be supplied by local CIRE projects. Once an identified load and any necessary generation sites have been identified, the owner builds a generation project.

The generation is located in the community and has a separate and direct connection to the local utility. The aggregator acts like a CCA, except the customers remain IOU customers. Some of the generation aspect of the customer's bill will need to be unbundled, as this generation will be provided by a third party.

The solution is based on the campus rate structure described in Section 7.2. The third party has agreements to supply a certain periodic kWh to each signed-up individual. The third party then exports all of the generator's energy to the local utility grid. The utility then provides and is compensated for the following services:

- transmitting the renewable energy to the customers
- billing and calculating the generation offset
- providing all additional and backup power
- providing all ancillary services

With third-party ownership, the third party takes all responsibility in sharing the generation among multiple owners and resolving any disputes regarding allocation of the renewable resource. The contract between the owner and the customer would be required to deal with such issues. Implementation of this scenario would require significant changes to existing utility regulation rules and would likely be a long and complex process.

7.4.3.2 Customer Ownership

Individual customer ownership of renewable generation for the customer's own use is well defined under the current regulatory regime. This section discusses potential models and needed reform for customers/property owners/site hosts to own and operate CIRE projects. An individual customer could install a large generator at their site — for example; a large warehouse has enough capacity for 1MW of soar but only 100kW of peak load.

A potential model to facilitate this would be for a customer to set up a contract with a utility as described in the previous example. One distinct disadvantage with this is that the customer would be responsible for rounding up other community members, contracting, and administration, and assume the risk of resource allocation. This coupled with the costs of financing the project would make this option unattractive for all but the minority of private customers.

7.4.4 Summary

Three examples have been described for enabling CIRE projects within a community and have been ordered in terms of their complexity to implement.

An IOU may be an obvious choice[17] to develop these CIRE projects as they have all the tools, experience, processes, and access to capital to allow CIRE projects to be developed. Changes to rates and regulations are required, but in California's shifting regulatory environment, these changes do not seem unreasonable.

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[17] Future revisions of this report will also investigate non-utility energy providers with these skills such as local municipalities, third party generators and energy service providers.

The SDGE sustainable communities scheme was a success with over 4MW of generation installed on consumers properties. The scheme worked through some of the issues that would entail about installing IOU equipment on consumers properties such as access, maintenance and installing liability. While the electricity was connected to the IOU's side of the meter, slight modifications to the scheme (with regulatory change) would allow the electricity to be connected to the consumers side of the meter or the electricity sold to them directly rather than the standard retail electricity that was purchased by the customer under the sustainable communities scheme.

Third-party ownership of CIRE models, while not possible in the current regulatory regime would likely increase CIRE projects should legislation be changed to allow this model in California. With third-party ownership, the third party takes all responsibility in sharing the generation among multiple owners and resolving any disputes regarding allocation of the renewable resource. There are third-party providers of heat services who are skilled in the application of billing, access to capital and all of the other skills needed to operate CIRE projects.

Customer ownership of CIRE projects is not expected to be a suitable vehicle for mass implementation of projects throughout California. An individual customer would have to have access to large volumes of capital, have a large appetite for risk, and be able to deal with complex energy contracts with multiple stakeholders, and be willing to enter into a new business that is likely substantially outside their existing knowledge or core business. In addition they would have to maintain an operational, reliable energy generating station. This may be suitable for a small number of community members but is not expected to facilitate the proliferation of community energy projects.

7.5 Model 4 - Microgrid

Model 4 applies to community members who are spread over multiple land parcels and city blocks, and whose energy is provided by centralized energy generation. The CIRE boundary has the ability to separate from the wider grid and operate independently as a microgrid.

7.5.1 Model Description

A microgrid in a CIRE context is an electric grid supplied from one utility distribution substation or feeder. The microgrid is self-sufficient, that is, within the electrical grid there is enough energy generation and energy storage to support all of the loads, or at least the critical loads for large communities. The microgrid can separate from the wider grid, or "island," in times of wider microgrid outages.

This CIRE model describes a community that is spread over multiple city blocks. This may be a designated eco-district, a large new development or redevelopment of city blocks, or an existing neighborhood, all of which are common in Central SoMa. The community may be made up of a mix of commercial and residential properties and a mix of building ownership and leases.

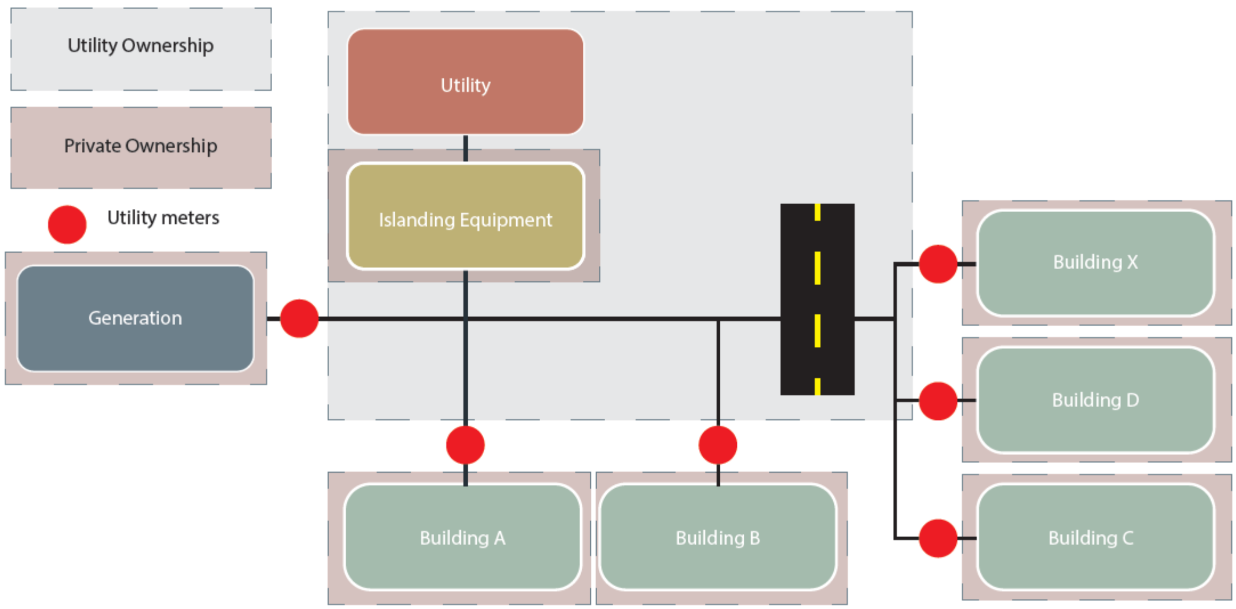
The CIRE project would involve installing a centralized generation plant (electricity only, heat/cooling only, or heat/cooling and electricity). The CIRE project would share this centralized generation with all community members in the project area. The community members may benefit from the centralized generation by reduced energy bills, greater local control or choice over type of energy supply (particularly renewable), and potentially greater resiliency if designed to "island" during a grid outage, with the help of energy storage and smart grid controls. In addition to centralized generation there can be local behind-the-meter generation with communication links to the master microgrid controller. This model would enable the community to become a net zero energy community.

The microgrid community has two ownership models and we will discuss the challenges each of these faces within this Section.

The first ownership model is a private ownership model and this is shown in Figure 9.

Within this model, a private third party owns and operates the complete CIRE system.

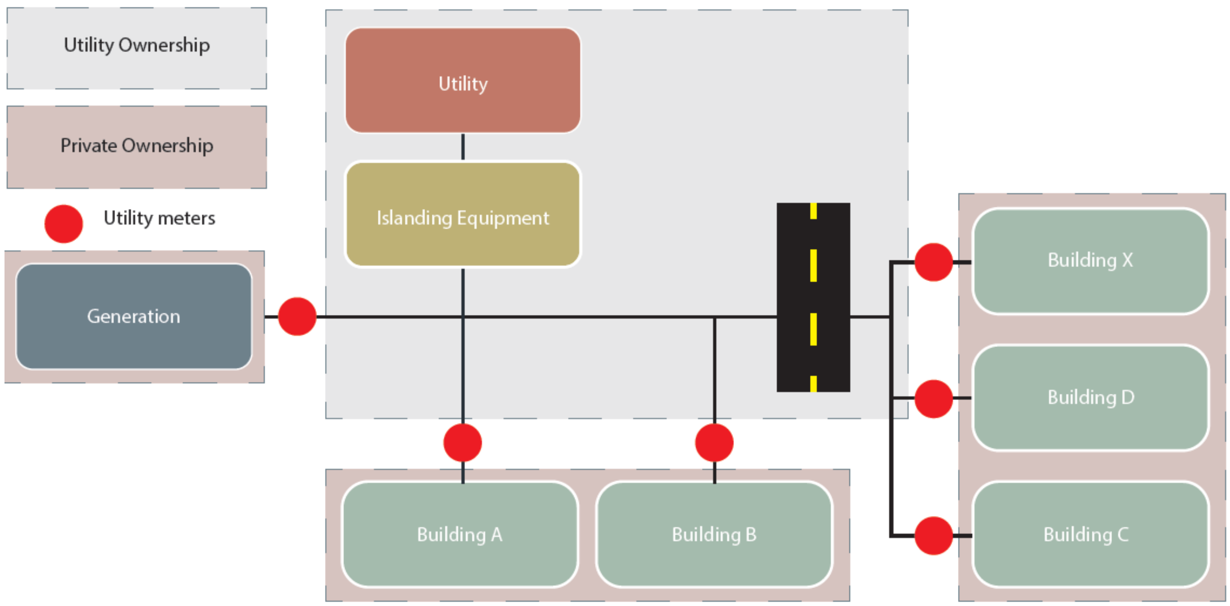
Figure 9: CIRE Model 4



The second ownership model is a utility ownership model and this is shown figure 10:

Within this model, the local utility owns and operates the complete CIRE system. A utility, in response to market demand of a community, developer, or other business needs, develops a CIRE system under the owner ship of the utility.

Figure 10: CIRE Model 5 Utility Ownership



7.5.2 Model Regulatory Challenges

Model 4 differs from Models 3 in that in a grid outage, the generation can continue to operate as a microgrid, independently of the wider grid. The microgrid is self-sufficient — within the electrical grid there is enough energy generation and energy storage to support all of the loads. The microgrid can separate from the wider grid in times of wider macrogrid outages.

In addition to the regulatory challenges discussed in the previous scenario this model has the additional complication of being able to island from the wider grid.

This raises the following questions:

1. How and when does the CIRE system island from the utility grid?
2. What safety measures are deployed?
3. How does the system reconnect to the wider grid?
4. Which customers can be served by a microgrid?
5. What utility business models are suitable for a microgrid?
6. How to change the existing rate structure?

Two solutions can enable this CIRE model, based on the following types of ownership and operation of the CIRE generation, storage, and islanding equipment:

1. utility ownership
2. third-party ownership

7.5.2.1 Utility Ownership

The equipment required for a microgrid is listed below:

- energy storage
- islanding equipment (switchgear, protection, communications, safety equipment)
- microgrid management system
- testing and operation of the islanding equipment

The cost of the equipment required to operate in an island mode for selected utility customers would need to be recovered from only the customers who receive an enhanced service. It would not be fair to spread the costs of microgrids to customers who do not receive this enhanced level of service.

There are two ways in which a utility could make a reasonable return on microgrid equipment:

1. a microgrid rate for microgrid customers
2. alternative utility regulation models

Microgrid Rate

In response to a market need or a community request, an IOU owns and operates a microgrid for the community. The utility determines the boundaries of when the system islands from the grid and actively controls the microgrid to maximize the electrical reliability of the microgrid. The business model for the microgrid is twofold. First customers of the microgrid have all of their energy needs over the course of a defined period provided by the on-site renewable resources, and the utility charges a premium to these customers for having 100% renewable energy. This can be much the same as the rates discussed in Models 2 and 3. The second rate increase is a reliability increase. Customers pay a premium for having uninterruptable power (subject to generation output and storage levels). The rates must be designed so that the IOU can make a reasonable return on the investment in line with the current regulatory regime.

Alternative Regulation Models

Alternative regulation models for utilities have the potential to spur utility investments in microgrids in the right areas, say areas that have poor reliability. A performance- (or results-) based regulation model may have the ability to balance customer and utility needs. It can incentivize utilities to innovate based on defined metrics that are important to utilities and consumers alike.

Performance-based regulation allows utilities to earn reasonable returns by delivering value to customers. Performance-based regulation includes incentives for cost reduction and improved service levels.

Changing the regulation model is no easy task. In the United Kingdom a performance-based regulatory model called RIIO (Revenue = Incentives + Innovation + Outputs) set price controls for network companies. The RIIO regulations have been implemented to address many issues similar to those facing the United States, such as ageing infrastructure, high penetration of renewable generation, and a changing generation mix. The UK underwent a multiyear consultation process to implement RIIO, and the first IOU plans are due for submission to the regulator in early 2014.

A performance-based regulation may include the following metrics on which a utility can receive regulated income (RIIO performance metrics):

- Consistent supply– a share in the value of interruptions prevented from power outages by grid modernization such as microgrids
- Environmental performance – incentives based on reducing greenhouse gas emissions such as by installing CIRE projects
- Customer satisfaction – incentives based on the results of customer satisfaction surveys
- Social obligations – addressing fuel poverty and providing service to vulnerable customers
- Timing and efficiency – connecting new customers
- Safety standards

A performance-based regulation method changes the cost-for-service regulation model of the utility. The revenue from the reasonableness of incurred costs can free up a utility to innovate and employ differing business models that align with customers' and the State's energy goals.

The San Diego Gas and Electric (SDG&E) Borrego Springs microgrid is a good example of a utility developing a microgrid to provide benefits to a community with reliability issues. SDG&E are conducting a pilot scale proof-of-concept test in San Diego, California of how a microgrid and DG may increase asset utilization and reliability of the power grid in a nationally scalable approach

7.5.2.2 Third-Party Ownership

Third-party ownership of the microgrid will include all items required to functionally operate as a microgrid, including the generation, storage, and controls equipment. There are US precedents of third-party community microgrid development work ongoing in the state of Connecticut, spurred by the devastation caused by Superstorm Sandy in 2012.

A barrier to the early adopters can often be the large up-front capital cost. A microgrid is much more than just an emergency power supply and requires specialized planning and design. It has to operate as a self-contained grid, managing the delicate balance of supply and demand while providing the necessary electrical safety functions.

Taking the microgrid concept outside single land/building owners presents fruitful yet complicated opportunities. A mixed-use area of a town/city is an ideal place for a microgrid, somewhere with a mix of commercial and residential use and differing load profiles. As commercial loads ramp down for the day, the residential sector's increase.

One a potential business model is for a microgrid developer to set up a microgrid with the security of a long-term PPA, similar to how a community solar scheme can operate, and reducing the up-front capital costs to the end user. The developer may be the building's developer or a separate third-party microgrid developer. As described for Models 3 and 4, the third-party developer still needs to follow the same processes and utilize the IOU's distribution assets to minimize regulatory hurdles.

Once an area is identified as a microgrid candidate, the utility could rent the distribution grid in this area at cost plus a rate of return to a third party that would develop and likely operate the microgrid. This third party would have a contract with each customer (similar to a PPA), where the customer would pay a fixed monthly charge based on their average demand.

CHAPTER 9: Conclusion

CIRE projects allow members of a community to have some or all of their electricity needs supplied from renewable sources. The objective of this report was to determine whether the current regulatory framework present barriers that may inhibit increased penetration of community renewable energy generation into the electricity network in California.

US citizens have a desire for renewable power based on the research presented in this document. There is a clear market need for renewable projects. People want renewable power, but not at all costs. A CIRE project — a centralized, shared, and economic generation source — has the potential to maximize the number of people who move to renewable energy by potentially reducing individual homeowner costs and complexity. CIRE projects provide other local benefits. Such benefits include reduced system losses, energy security, deferred need for transmission lines and increased renewable energy content.

Individual home and business owners are not best placed to develop CIRE projects. CIRE projects involve access to capital needs, contract negotiations, right of way negotiations and coordination. To develop a CIRE project an entity with experience in all of these areas is required. Such entities may include IOU's, municipalities, and third party generation developers.

This report has considered several potential models of CIRE generation. The existing regulatory framework does not allow all CIRE projects to be fully implemented in California. The main impediments to CIRE project implementation are the barriers to entry for both utility and private developer ownership of projects, which include the following:

- the need to become a regulated utility when distributing energy to more than two community members
- the ownership of generation and distribution assets
- the existing electricity rate structure
- incumbent utility business models and regulation

There are opportunities to allow the proliferation of CIRE projects in California. Some of the solutions will satisfy the majority of stakeholders, while some are more controversial and require significant regulatory changes.

The passing of SB 43 has created a regulatory path to allow individual property owners the opportunity to purchase clean, renewable power without having to install generation assets at their location. While SB 43 provides a pathway for individuals to obtain clean power, it does not present a local, community wide solution. It also does not allow third parties to develop community energy systems and sell and distribute that energy directly to community members. SB 43 provides 600MW of potential renewable energy capacity for California. Within the 600MW capacity, 100MW is allocated for CIRE type projects and this makes a meaningful contribution to Governor Brown's local renewable energy targets. However, SB 43 will not get California to its targets alone and therefore re-enforces the need for new CIRE models to increase local renewable generation.

In campus settings, the design of a new rate to allow campus generation to be shared will satisfy campus owners and also provide the existing IOU with a revenue stream for the utilization of their assets. A rate such as this has potential to increase CIRE projects at multi-parcel campuses which are common throughout California. A rate such as this does not require regulatory overhaul. The rate has a precedent in a non-California IOU and the rate design can be based on the experience of other IOU implementation and design efforts.

While a campus rate for CIRE projects will provide a useful injection of CIRE projects, the real opportunity for proliferation of CIRE projects is in multi-owner districts and microgrids. Such systems can be constructed in every neighborhood in California. In multi-owner districts we have identified two suitable entities that can own and operate CIRE projects. These are traditional IOU's and also third party developers. An IOU may be an obvious choice to develop these CIRE projects. Changes to rates and regulations are required, but in California's shifting regulatory environment, these changes do not seem unreasonable. Third-party ownership of CIRE models, while not possible in the current regulatory regime would likely increase CIRE projects should legislation be changed to allow this model in California. The most efficient method for increasing CIRE projects would be regulatory reform to allow both IOU's and third parties to, under a certain defined framework, develop CIRE projects in community's that demonstrate a desire to have all or some of their electricity needs supplied by local renewable generation.

There is a clear need for CIRE projects in California and the most efficient method at increasing CIRE projects is to allow the development of CIRE projects by both the existing IOU's and competitive third parties. Rates and regulations will need to be modified to allow the proliferation of CIRE projects in California. The required changes to legislation is recommended to be publically researched and consultations undertaken. CIRE projects present a real opportunity in California to reach and then exceed Governor Brown's 12,000MW target of clean, local, renewable energy.

GLOSSARY

Term	Definition
AB	Assembly Bill
behind-the-meter generation	Generation installed on an individual customer's electricity distribution system, behind the utility meter.
CAISO	California Independent System Operator
CARE	California Alternate Rates for Energy
CCA	Community Choice Aggregation
CCSF	City and County of San Francisco
CIRE	Community Integrated Renewable Energy
CPUC	California Public Utilities Commission
DG	distributed generation
direct access	large electricity users like retailers, manufacturers, commercial campuses, and universities buy their electricity directly from energy service providers instead of the utility companies
eco-district	an urban planning tool that integrates objectives of sustainable development and reduces the ecological footprint of an area
EEI	Edison Electric Institute
ESP	energy service provider
FERC	Federal Energy Regulatory Commission
FIT	Feed-in Tariff
IOU	investor-owned utility
kV	kilovolt
kW	kilowatt
local renewable power	generation installed on the distribution network so that benefits are gained locally
microgrid	Microgrids are small-scale versions of the centralized electricity system. They include local generation and or energy storage. They achieve specific local goals, such as reliability, carbon emission reduction, energy

	arbitrage, diversification of energy sources. They have the ability to island from the wider grid and operate independently.
MW	megawatt
NEM	net energy metering
PG&E	Pacific Gas and Electric
PPA	power purchase agreement
PURPA	Public Utility Regulatory Policy Act
ReMAT	Renewable Market Adjusting Tariff
RPS	Renewables Portfolio Standard
SB	Senate Bill
smart grid	A smart grid is a modernized electrical grid that uses information and communications technology to gather and act on information, such as information about the behaviors of suppliers and consumers, in an automated fashion to improve the efficiency, reliability, economics, and sustainability of the production and distribution of electricity (USA, 2013)
WDT	wholesale distribution tariff

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Department of Environment

CIRE - Central Corridor

NRG Existing Conditions

Final | March 20, 2014

This report takes into account the particular instructions and requirements of our client.

It is not intended for and should not be relied upon by any third party and no responsibility is undertaken to any third party.

Job number 214757

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Contents

Tables

Figures

1 Introduction

NRG owns and operates a district heating system in downtown San Francisco (the system). This system is comprised of two energy centers that generate steam, and a 10 mile underground pipe network that distributes this steam to buildings in a 2 square mile area of the central business district of San Francisco. These buildings, or "steam customers," utilize the steam for a variety of uses including:

- Space heating
- Domestic hot water
- Industrial processes
- Air conditioning

Figure 1 provides an overview of the NRG operations in downtown San Francisco.

Figure 1: NRG San Francisco Overview (Image courtesy NRG)

Established in 1930, the system was originally owned by Pacific Gas and Electric Co. (PG&E) and was comprised of 5 separate systems. Continual system growth and interconnection led to the eventual consolidation into the two existing energy centers. NRG Thermal (a wholly owned subsidiary of NRG Energy Inc.) bought the system in 1999.

Unless otherwise stated in footnotes, information and data in this document was gathered through the following sources:

- A CIRE team tour of the NRG Energy Center on Jessie St. on September 20th 2013
- www.nrgthermal.com
- Correspondence with the energy center general manager Gordon Judd

Photograph 1: CIRE Team Tour of the NRG Energy Center Station 'T'

2 Plant Overview

The system comprises of two energy centers or "plants," known operationally as Station T and Station S.

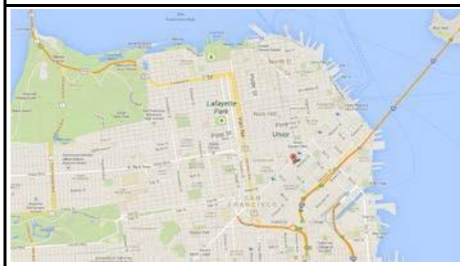
2.1 Station T

Located at 460 Jessie Street, Station T houses six boilers that collectively have the capacity to produce 442,000 lb/hr of high pressure steam. All boilers are natural gas fired, and No.2 diesel is available as backup fuel on some of the units.

Station T is the primary steam generating plant for the system, and runs continuously through the year. Peak plant output typically occurs between December and March, and the plant operates at approximately 30% capacity over the summer months when space heating demands are greatly reduced.

Information about the thermal and emission efficiency of boilers at station T is provided in section 4.

Table 1: Station T Summary

STATION T				
LOCATION 460 Jesse Street	Boiler	Capacity lb/hr	Primary Fuel	Backup Fuel
	3	55,000	Natural Gas	No. 2 Diesel
	4	55,000	Natural Gas	No. 2 Diesel
	5	50,000	Natural Gas	No. 2 Diesel
	6	100,000	Natural Gas	None
	7	100,000	Natural Gas	No. 2 Diesel
	8	82,000	Natural Gas	No. 2 Diesel[1]

2.2 Station S

Located at 1 Meacham Place, Station S houses one active boiler that can produce 40,000 lb/hr of high pressure steam. All boilers at Station S are natural gas fired.

Station S is a "peaking plant" and operates only to supplement primary steam generation at Station T.

Information about the thermal and emission efficiency of boilers at station S is provided in section 4.

Table 2: Station S Summary

STATION S				
LOCATION 1 Meacham Place	Boiler	Capacity lb/hr	Primary Fuel	Backup Fuel
	1	40,000	Natural Gas	None

[1] In process

3 Distribution Overview

The system comprises of approximately 10 miles of underground steam piping. This piping network delivers steam from the 2 energy centers to approximately 170 buildings in San Francisco's central business district. This network of underground pipes spans approximately a 2 square mile area, and delivers over 700 million lb of steam annually.

The heating system also comprises of approximately 1.5 miles of condensate recovery piping, which transports condensate, or "spent steam," back to the energy centers. By recovering condensate, NRG reduces the amount of "virgin" feed-water required to generate steam. The condensate return pipe network is not as holistic as the steam supply network, and many buildings, or "steam customers" currently use the condensate on site for processes such as cooling tower makeup water and irrigation, or send it to the city sewer system.

Information about the water efficiency of the system is provided in section 4.

4 Current Operations

4.1 Annual Resource Consumption

The primary resources consumed by the system are natural gas and water for boiler firing and steam feed water purposes respectively. The system also uses electricity for condensate pumping, and building power, controls, and lighting purposes. Resource consumption for fiscal year 2012 is tabulated below:

Table 3: Resource Consumption

Resource	Consumption	Unit
Natural gas	1,192,165,000	cub-ft
Water (Potable)	824,933,000	lbs
Electricity	1,856,821	kWh

4.2 Annual Commodity Generation

The primary commodity generated and delivered by the system is high pressure steam. Steam generation is measured at the source (i.e. the amount leaving the energy centers) while delivery is measured at the point of use (i.e. the buildings or "steam customers"). Both points of measure are important as together they reflect the efficiency of the distribution pipe network.

Condensate is a "recovered" commodity, and is measured at the energy centers.

Commodity generation, distribution and recovery for fiscal year 2012 are tabulated below:

Table 4: Commodity Generation, Distribution, and Recovery

Commodity	Amount	Unit

Commodity	Amount	Unit
Steam generation (Plant meters)	786,276,000	lbs
Steam delivered (Customer meters)	724,906,000	lbs
Condensate return	108,735,900	lbs

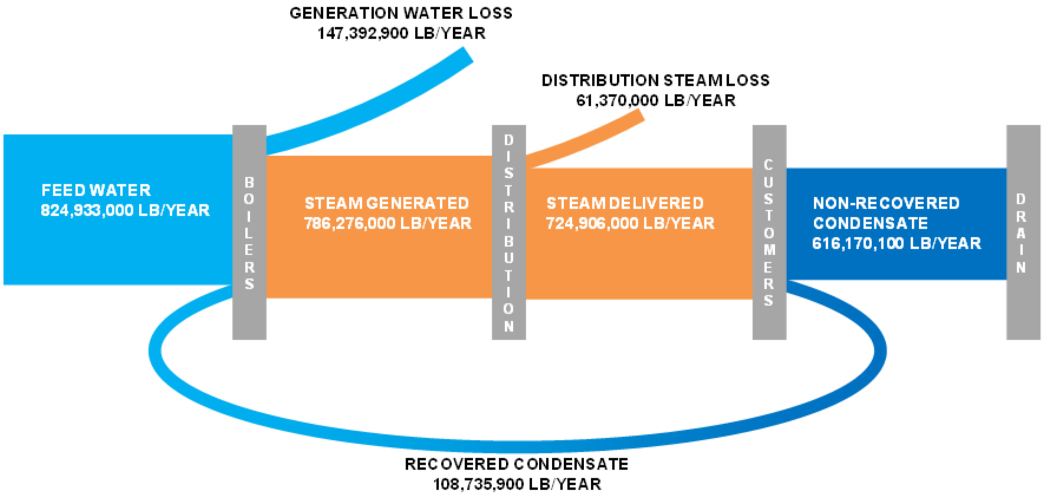


Figure 2: Current Resource and Commodity Flow Diagram

4.3 Current Performance

The tables below summarize the thermal, water, and emission performance system based on the 2012 fiscal year data presented in the previous section.

Table 5: Thermal Efficiency Data

Thermal Metric	Efficiency
Station S generation	Standby/peaking service only, < 1.0% of total. Efficiency not tracked
Station T generation	78%[2]
Delivered to near customers, with condensate return	80 - 82%
Delivered to far customers, without condensate return	67 - 70%
Overall system delivered	71%[3]

Table 6: Water Efficiency Data

Water Metric	Efficiency

[2] Calculated as total annual steam generation over total annual gas consumption
[3] Calculated as total annual delivered steam over total annual gas consumption

Generation	84%[4]
Overall system	12%[5]

Table 7: Emissions Data

Boiler	Emissions
Boiler 3	15 ppm NOx
Boiler 4	15 ppm NOx
Boiler 5	30 ppm NOx
Boiler 6	30 ppm NOx
Boiler 7	15 ppm NOx
Boiler 8	9 ppm NOx

5 Planned Improvements

NRG is currently planning the following 3 system improvement projects:

- A condensate recovery project that is expected to improve the overall system water efficiency to approximately 50% by collecting condensate from NRG customers that are geographically close to generation plants, and that are large in scale
- A ground water recovery project, scheduled for install in 2014. The project will result in the use of ground water in lieu of potable water, for approximately 40%-60% of the total system water consumption
- A 500 kW combined heat and power (CHP) project scheduled to begin operation by mid-2014. The project is expected to meet approximately 80% of the systems electrical consumption

For further information on planned, and other potential improvements ideas, refer to the document titled "Task 3B: NRG Potential Improvements."

[4] Calculated as generation output (steam generation) over generation input (feed water plus condensate return)

[5] Calculated as system output (condensate return) over system input (feed water plus condensate return)

APPENDIX B:
Task 3B: Community Energy and Enabling Technologies Use Case - Existing District Heating Systems

Energy Research and Development Division
FINAL PROJECT REPORT

COMMUNITY INTEGRATED RENEWABLE ENERGY PROJECT

Task 3B: Community Energy and Enabling Technologies Use Case - Existing District Heating Systems

Prepared for: California Energy Commission
Prepared by: Arup, for the San Francisco Department of Environment

MARCH 2014
CEC-500-2014-MAR

CHAPTER 1: Workshop

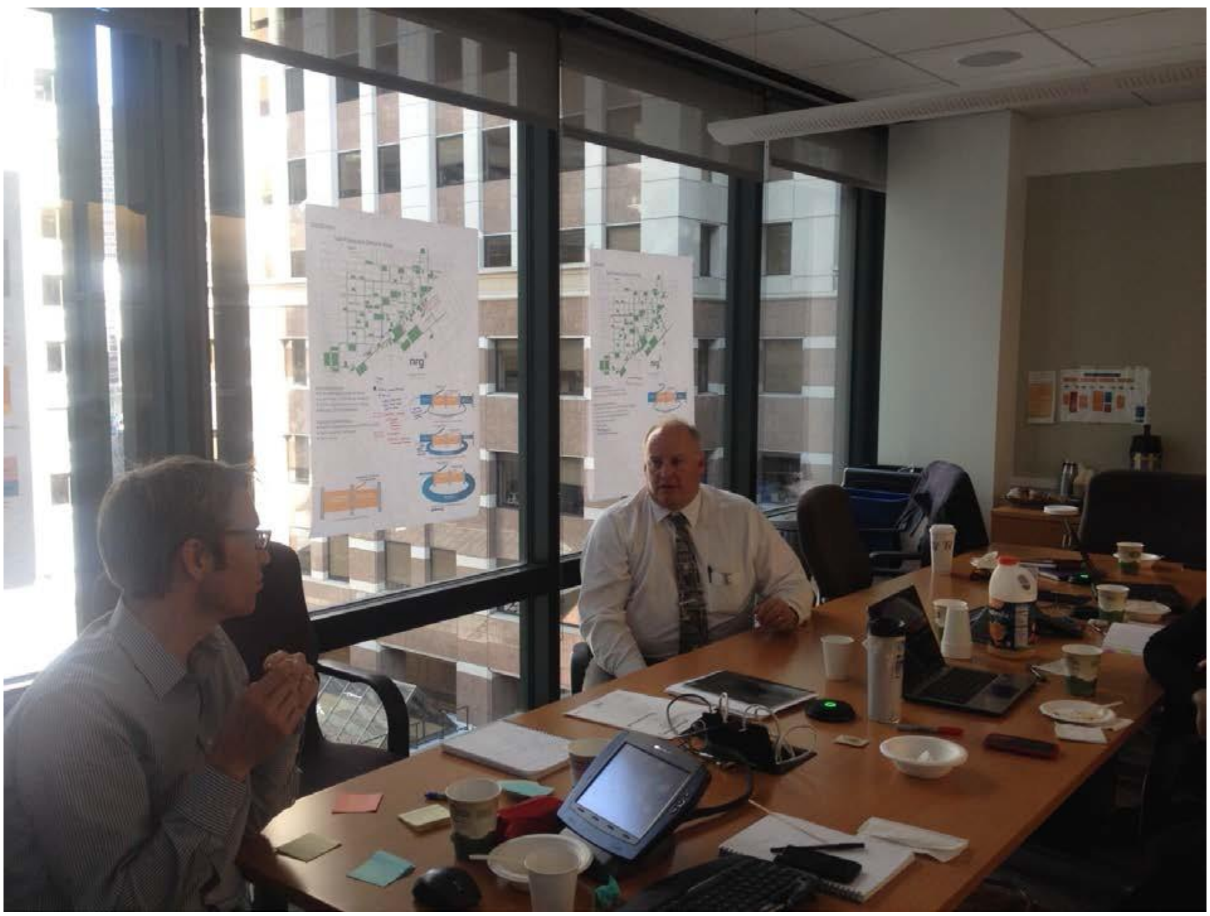
On January 23, 2014, members of the project team from the City and County of San Francisco (CCSF), NRG, and Arup met to brainstorm and develop ideas for improvements to the existing NRG district energy system in downtown San Francisco. Table 1 summarizes the workshop attendees.

Table 1: Working Session Attendees

Attendee	Organization
Russell Carr	Arup
Cole Roberts	Arup
Afaan Naqvi	Arup
Nadine Anseeuw	Arup
Gordon Judd	NRG
Danielle Murray	CCSF

Materials used during the workshop can be found in Appendix B.

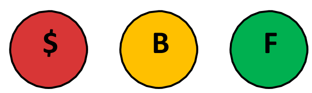
Figure 1: Workshop Attendees Discussing CIRE



Prior to the workshop, the team identified initial potential improvements. These were discussed further at the workshop and documented along with additional strategies identified during the workshop.

During the workshop, the team used a “blue-sky” approach toward improvement measures. The blue-sky method means that ideas were first identified and documented without consideration of specific financial, spatial, and/or regulatory constraints. These constraints were then applied as filters to the measures, resulting in measures recommended for further study and measures found to be currently infeasible.

The primary filters applied were cost, benefit, and feasibility, as represented by the following icons. The icon colors represent their relative rating (red, yellow, and green representing adverse, moderate, and good, respectively). For example, the icons below show a high cost (adverse), with moderate benefit, but high feasibility.



CHAPTER 2: Community Integrated Renewable Energy Strategies

This section summarizes measures identified specifically as potential Community Integrated Renewable Energy (CIRE) projects for existing district heating schemes.

2.1 Renewable Fuel

Two of the value propositions of district energy are increased fuel flexibility and the opportunity for real-time and competitive fuel purchasing. These are enabled by the centralization of the energy conversion function, which in turn is scaled up due to aggregation of loads. The resulting scale and single point of fuel use makes utilization of renewable fuels in district energy systems more feasible than at a building level.

Depending on policy, goals, and fuel availability, renewable fuels can be used to supplement, reduce, or entirely replace the use of fossil fuels such as natural gas. Two primary forms of renewable fuels are presented in the following sections.

2.1.1 Biogas

Renewable biogas is generated through the anaerobic digestion of the organic portion of solid waste, manure, sewage, and plant material. Once upgraded (removal of carbon dioxide [CO_2] and trace gases), biogas can be used as a fuel source for generating thermal and electrical district energy. There are broadly two methods by which biogas can be used in district energy systems: direct biogas and directed biogas.

Direct biogas refers to the on- or off-site generation of biogas for use directly as a fuel source on-site.

Directed biogas, or pipeline biomethane[1], is biogas that meets pipeline-quality natural gas standards. Directed biogas is typically created at centralized locations such as wastewater treatment plants, large farms, and landfills and other solid waste sites. Due to the infrastructure expense and energy created and used, it is typically not practical to dedicate an individual pipeline from the digester to a project site. Biogas has a more sustainable impact when it is injected into an existing natural gas pipeline (as pipeline biomethane) that is connected to the district energy plant.

Given that district heating plants in urban settings will often be space-constrained, district heating providers are likely to find directed biogas to be a much more feasible option for biogas than direct biogas.

To pursue directed biogas fuel supply, district energy providers will have to contract directly with an in- or out-of-state biogas-generating entity. Such a contract would have to ensure that all measurement and verification requirements are in place to ensure that the quantity and

---

[1] As defined by Article 5, Sections 95800 to 96023, Title 17, California Code of Regulations.

quality of the biogas injected into the network in fact offsets an equal amount of natural gas supplied by the network.

Directed biogas contracting may increase fuel costs for district energy providers. One way to manage those additional costs is to pass the premium on to customers through a "green energy customer" program that would entitle customers to ownership of the associated Renewable Energy Certificates in an amount proportional to their source energy use.

San Francisco Context: $ B F

The system currently uses natural gas as boiler firing fuel, consuming an estimated 1,190,000,000 ft^3 annually. This is equivalent to the annual gas use of approximately 9,085 average California homes[2] and causes an estimated 63,500 tons of CO_2 emissions[3] locally at the NRG plants. On-site biogas generation is currently infeasible at the existing NRG plants. Directed biogas contracting is a possibility that should be explored. It is expected that customers would be receptive to electing to have biogas purchased for all or a portion required to generate the steam they consume.

Without clearly identified existing local biogas suppliers, direct biogas is currently an infeasible strategy for NRG to pursue. In-state and out-of-state biogas suppliers should be engaged on an ongoing basis to understand potential directed biogas market rates and so that the success of a "green energy customer" can be assessed.

EQUIVALENT GAS USE BY	EQUIVALENT TO
9,086	**63,500**
CALIFORNIANS ANNUALLY	TONS OF CO_2

2.1.2 Biomass

Biomass is plant or plant-based material that can be used directly as a source of thermal energy through a combustion process. Wood is the primary fuel used in the biomass energy industry, with agricultural and forestry waste being the most prevalent sources.

---

[2] Average annual Californian gas consumption based on 60,000 cub-ft per capita per http://www.energyalmanac.ca.gov/naturalgas/per_capita_consumption.html and an average household size of 2.89 per http://www.indexmundi.com/facts/united-states/quick-facts/california/average-household-size#map

[3] Assuming 11.71 lbs/therm for natural gas combustion.

Similar to the anaerobic digestion and gas cleanup processes required to generate useable biogas, biomass also requires careful fuel preparation. This typically entails pelletization of wood to maximize surface area and subsequently maximize combustion efficiency. Unlike biogas, however, biomass cannot be used in lieu of natural gas directly in standard gas-fired boilers. District energy providers will instead have to install biomass boilers or pursue burner retrofits in order to utilize biomass.

Unlike biogas, which can be injected into a grid at one point and be effectively consumed at the district energy plant, biomass requires physical transportation to the district energy site. This often requires additional loading, circulation, and, most importantly, storage space on-site, making it a challenging strategy to implement at existing district energy systems.

San Francisco Context: $ B F

Though NRG has considered biomass as an alternate fuel supply, its generation plants are spatially constrained and would not support multiple-day fuel storage capacity. However, a single-boiler retrofit to support tri-fuel capability (biomass in addition to the existing natural gas and diesel firing capability) would result in a more manageable fuel delivery and storage operation.

The idea of sourcing woody and green waste from San Francisco Recreation and Park facilities such as Golden Gate Park was discussed at the workshop. However, all of this waste is currently composted and reused on-site, and is therefore not currently a potential biomass fuel source.

Figure 2: On-site Composting Facility in Golden Gate Park

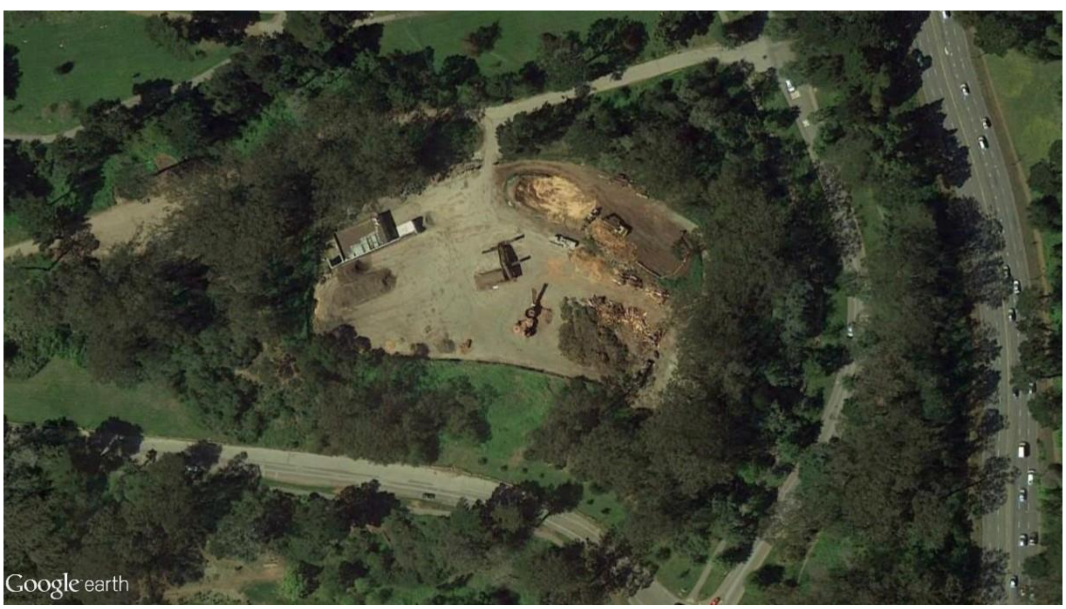


Photo Credit: Google 2014

2.2 Solar Thermal Systems

Solar thermal systems generate hot water through the capture and transfer of solar energy to a thermal system (heating hot water or domestic hot water system). This is typically achieved by capture of solar energy in collectors that contain a working fluid. This fluid is circulated between the collectors and a heat exchanger, where the solar energy is ultimately transferred to the thermal system.

Like photovoltaics, solar thermal collectors operate most efficiently when unshaded, and they are therefore typically installed on building rooftops and/or above parking garages. Supply temperatures and efficiency varies in different ambient conditions for various collector technologies. The most common collector types are flat plate and evacuated tubes, as illustrated in Figure 3.

Figure 3: Flat Plate and Evacuated Tube Collectors

Integrating solar thermal systems into existing district energy systems requires careful consideration of several key system and climatic variables.

2.2.1 Possible Installation Configurations

In low- and medium-temperature hot water district heating schemes, solar thermal systems could be used to preheat return water at the central plant or to raise supply temperatures in the network at customer or “near customer” locations.

In high-temperature hot water district schemes, solar thermal systems may be limited in application to return water heating only, depending on the collector technology output capability and the operating temperature of the district heating scheme.

In district steam schemes, solar thermal systems can be used to preheat boiler feedwater or to raise condensate return temperature (if condensate is returned to the generation plants).

Solar thermal systems will tend to have limited, if any, application in district cooling systems.

2.2.2 Site and Configuration Selection

As mentioned above, there are various configurations in which solar thermal systems can be incorporated into existing district energy schemes. Selecting between these configurations will require additional consideration of site characteristics and project goals.

For example, solar thermal collectors will operate most efficiently at lower entering water temperatures, and so return water heating will tend to yield better energy efficiency than supply water heating in district hot water systems. Similarly, boiler feedwater heating will tend to yield higher energy efficiency than condensate return heating in district steam systems.

However, the location, neighboring buildings, and topography of the district energy scheme may result in very limited unshaded rooftop area at the generation plant, with larger parcels for potential collector installation available at customer and/or intermediate sites. Such cases would require a decision regarding the trade-off between optimal system efficiency and optimal system contribution.

2.2.3 Tilt Angle

For domestic and low-temperature heating applications, solar thermal systems will typically be installed with minimal tilt to maximize overall annual system contribution. This is due to the year-round nature of domestic water heating demands, for which low tilt angles capture the maximum amount of solar energy annually.

Figure 4: Installation Examples – Low Tilt Flat Plate, High Tilt Evacuated Tube Collector

For high-temperature and winter heating applications, collectors will typically be installed at higher tilt angles. This is due to the nature of space heating loads, which peak in the winter, when the sun is generally lower in the sky. Higher tilt angles are therefore used to maximize solar energy capture specifically during these peak heating demand periods, rather than steadily year-round.

2.2.4 Local System Impacts

Integrating solar thermal systems in existing district energy schemes can result in local operating impacts, including variations in differential pressure and temperature.

If installed at customer or other network periphery locations in hot water systems, increased local differential pressures may be beneficial in that they may enable turndown of distribution pumps back at the generation plant. However, depending on the district and solar system temperatures, integration of solar thermal systems can also reduce supply temperatures to customers locally. For both of these reasons, there could be a need to redesign customer interconnections and/or distribution substations.

For installations at or near generation plants in hot water systems, the increased differential pressure can similarly cause a need for recalibration, or even redesign of the district distribution pumps.

For boiler feedwater preheating in district steam schemes, increased differential pressure will have to be assessed to ensure that suitable feedwater system and boiler working pressures are maintained.

2.2.5 Rebates and Incentives

Existing district energy schemes may be eligible for capacity- and/or performance-based rebates and incentives for solar thermal integration projects. The potential trade-off between system performance and system size will need careful consideration in scenarios where such rebates and incentives are crucial for project success.

San Francisco Context: $ B F

Boiler feedwater preheating represents the most efficient integration configuration of solar thermal systems into the existing San Francisco district heating system. However, the NRG generation plants have limited rooftop area and some of the neighboring buildings to the south and west are taller than the generation plant, shading portions of this roof area. Together, these factors would greatly limit the size of such a solar thermal system, especially when compared to the magnitude of heat that is generated and distributed by the system.

Alternately, solar thermal systems could be integrated to heat condensate at a strategic location along the return path. One such location has been identified as the roof of the Moscone Center, where an unshaded solar thermal system with a much larger capacity could be installed. This concept is recommended for further study.

CHAPTER 3: Energy and Resource Efficiency Strategies

This section summarizes potential energy and resource efficiency and improvement measures for existing district energy systems that fall outside of the CIRE category.

3.1 Condensate Recovery Expansion

Condensate recovery is the collection and reuse of water after steam has been consumed by district energy customers. Recovering condensate (or "spent steam") offsets the amount of potable water consumed to generate new steam by returning water to the central plant. Recovering condensate back to the central plant also results in energy savings, as condensate is warmer than potable water and so less energy is spent heating up steam feedwater.

Condensate recovery is applicable to only steam-based district energy systems. By contrast, hot-water-based district energy systems are essentially "closed loop" systems that consume a minimal amount of potable water.[4]

A 100% condensate recovery rate is almost always cost prohibitive and impractical. For the purposes of this study and the existing San Francisco NRG system, the following two condensate recovery scenarios are identified as potential improvements to existing steam-based district energy systems.

3.1.1 50% Recovery

To achieve a 50% recovery rate, existing district systems should identify opportunities to expand condensate recovery piping to customers that are geographically close to the generation plants and that are large steam users. If successful, these expansions will result in the greatest amount of recovered condensate for the least amount of additional infrastructure and cost.

San Francisco Context: $ B F

As indicated in the *Task 3B.1 NRG Existing Conditions* report, the NRG system currently recovers between 12% and 15% of spent steam in the form of condensate returned to the central plant.

NRG is currently undertaking the expansion of the condensate recovery system, which will result in a recovery rate of approximately 50%. As indicated, this expansion project will require a moderate capital cost but will result in a beneficial amount of potable water and energy use reduction.

[4] Initial hot water district energy system charging and blowdown water do entail some water consumption, though typically insignificant compared to unrecovered condensate in steam district energy systems.

The distribution map in Figure 5 shows the existing condensate recovery piping network and planned future expansion.

Figure 5: NRG Steam Distribution and Condensate Recovery Map

3.1.2 75% Recovery

To achieve approximately 75% condensate recovery, existing district energy operators will typically have to target some remote customers located at the periphery of the steam distribution network, as well as some of the smaller steam users. Expanding the condensate recovery network to these customers will generally have diminishing returns compared to the capital expenditure required and should be studied on a case-by-case basis. Existing underground utilities and interconnections may also pose challenges that will require case-by-case consideration as existing district steam systems explore condensate recovery network expansion.

San Francisco Context: $ B F

Increasing the condensate recovery rate to approximately 75% represents a high cost for the San Francisco NRG system with only a moderate water and energy reduction benefit. This is due to the significant condensate recovery infrastructure that would need to be added to reach customers that are not only farther away but that will return incrementally smaller amounts of condensate to the generation plant.

Figure 6,

Figure 7, and Figure 8 illustrate the current, 50%, and 75% condensate recovery scenarios, respectively.

Figure 6: Current NRG Condensate Recovery

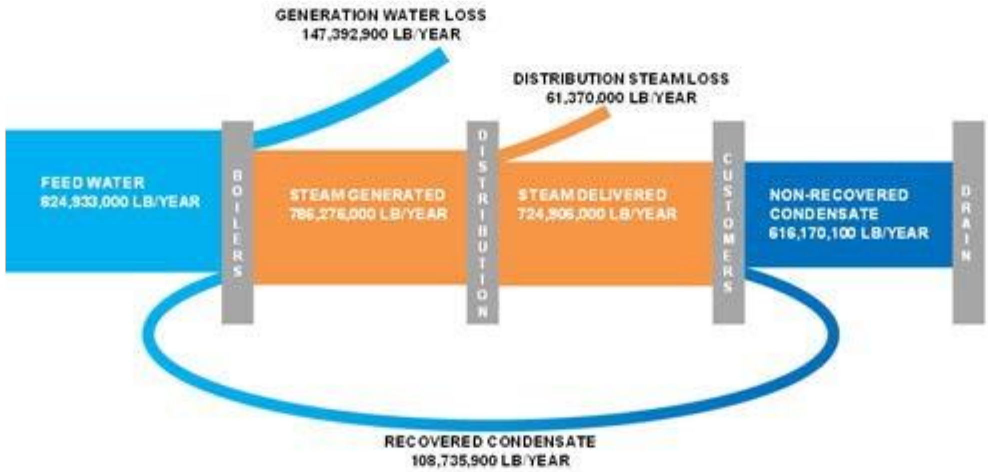


Figure 7: Planned Condensate Recovery – 50%

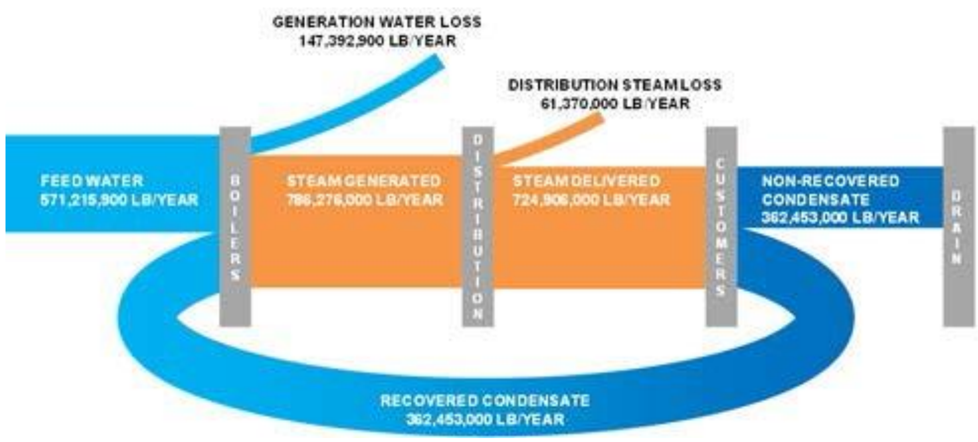
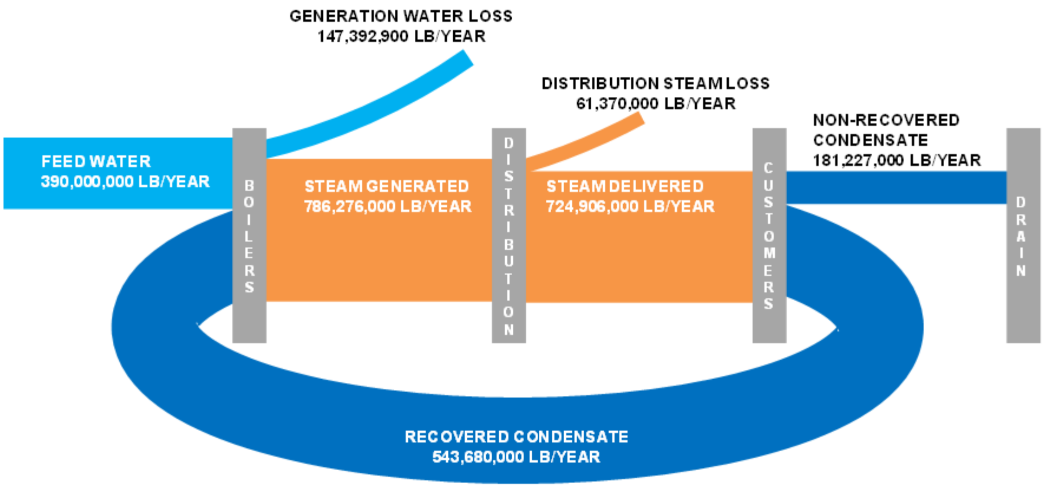


Figure 8: Theoretical 75% Condensate Recovery



3.2 Pipe Insulation and Repair

District thermal systems distribute energy over long distances, and distribution losses are therefore a key factor in overall system efficiency. Ongoing insulation and pipe repairs are essential in reducing direct energy losses that result in thermal degradation and can create supply temperature and/or steam quality/grade issues. Ongoing repair and maintenance of pipes and insulation is also important for medium loss prevention (water, or steam and condensate), which is typically an issue in old, legacy steam, or high-temperature district energy systems.

Having an improvement and maintenance plan is highly important to maintain the efficiency of any district system. Though a holistic upgrade to the distribution system may not always be feasible, the costs and benefits of piping and insulation repair and improvements should be assessed and pursued on an ongoing basis.

San Francisco Context: $ B F

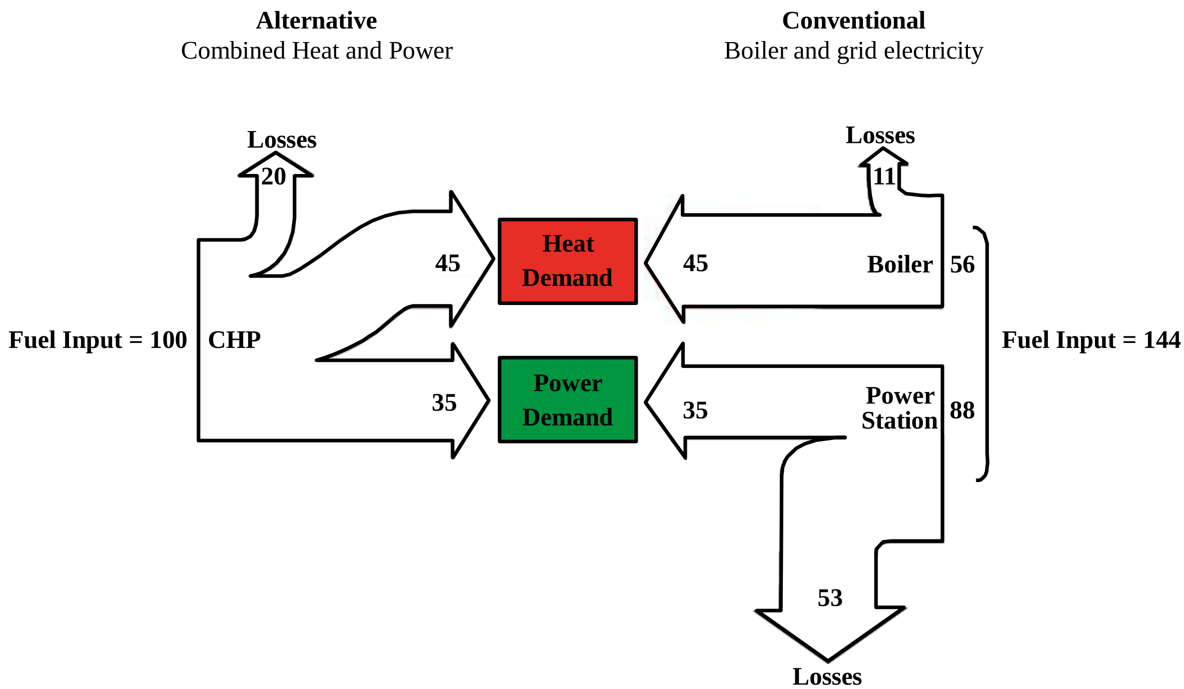
The NRG system distribution consists of approximately 10 miles of piping that connects the two NRG stations to its customers. Approximately 8% (61,000,000 lbs) of all steam generated is currently lost through the distribution piping network due to leaks. Maintenance and improvement of the distribution system require identification and repair of distribution sections causing these losses. This is seen as a feasible but "moderate" cost and benefit exercise.

Figure 9: NRG Steam Distribution Losses

3.3 Combined Heat and Power

Combined heat and power (CHP) refers to the simultaneous generation of heat and power from small- to medium-scale centralized energy systems. CHP is a highly efficient way of delivering these two forms of energy compared to the more conventional method of utilizing a boiler for heating and the electrical grid for power, as illustrated by Figure 10.

Figure 10: CHP versus Conventional Energy Supply



CHP is most commonly used in district energy schemes due to the proximity of thermal demands that can accept the heat that is otherwise wasted in the electricity generation process.

CHP systems are most efficient when they are sized to meet base loads, such that they can operate continuously at their optimal operating point. Since distribution of electricity across a public right-of-way is challenging and often not feasible, a majority of CHP schemes are sized with a dual load limit (thermal and electrical), whereby,

- the electricity generation is limited by the base electrical load of the generation plant
- the thermal generation is limited by the base thermal load of the overall district energy scheme

For district energy schemes with large chilled water loads, this dual restriction often results in a thermal load limit; whereas in schemes with minimal or no chilled water loads, this typically results in a limit equal to the electrical base load of the generation plant itself.

In addition to these load characteristics, operators will need to assess the spatial, capital, and operating cost impacts associated with integrating CHP into their existing district energy schemes. These vary significantly by CHP technology and require careful case-by-case study.

San Francisco Context: $ B F

The NRG district energy system currently consumes approximately 1,850,000 kWh of electricity annually. This is equivalent to the average annual electricity use of approximately 275 Californians[5] and causes an estimated 485 tons of CO_2 emissions[6] regionally.

EQUIVALENT ELECTRICITY USE BY	EQUIVALENT TO
275	**485**
CALIFORNIANS ANNUALLY	TONS OF CO_2

NRG is currently planning a CHP project scheduled to begin operation by mid-2014. The 500 kW CHP project will include two 250 kW generators that will meet 80% of the system electrical consumption, including an on-site reverse osmosis plant used by the system. The heat generated in the electricity generation process will be utilized for boiler feedwater preheating, offsetting boiler firing natural gas consumption.

[5] Average annual California per capita electricity consumption is 6,721 kWh/year per California Energy Commission 2010 data.

[6] Average PG&E grid electrical emissions are 0.575 lb/kWh per pge.com.

An alternate to this scheme could entail a larger CHP plant, sized to meet the thermal base load of the plant, in which case excess electrical generation would need to be sold back to a local off-taker such as a local utility. Further information about such a scheme can be found in CIRE Task 2: Community-Distributed Generation (Regulatory Policy) Report.

3.4 Groundwater Recovery

Groundwater can be recovered and reused as an alternate to potable water for certain district energy functions including boiler feedwater and cooling tower makeup. As these functions require a steady and significant flow of water, groundwater recovery is most suitable for steam-based district heating systems and district cooling systems that utilize cooling towers. Hot-water-based district energy systems are essentially "closed loop" systems that consume a minimal amount of potable water.[7]

Operators of existing district energy schemes should study the physical and financial feasibility of groundwater recovery on a case-by-case basis. Factors including local topography, rainfall, groundwater, and the extent of additional infrastructure required to recover groundwater will factor in heavily into the equation. Opportunities to partner with neighboring sites and/or projects with existing groundwater recovery infrastructure should be prioritized. The feasibility of groundwater recovery and reuse will improve drastically where such entities actively recover groundwater in an amount that exceeds their demands.

San Francisco Context: $ B F

Groundwater recovery is an attractive strategy for NRG as there are three existing neighboring sites that are already actively removing groundwater. These sites not only are within close proximity of the NRG generation plant, as illustrated in **Error! Reference source not found.**, they currently do not use the groundwater and instead drain it to the local sewer system.

[7] Initial hot water district energy system charging and blowdown water do entail some water consumption, though typically insignificant compared to unrecovered condensate in steam systems and cooling tower makeup in district cooling systems.

Figure 11: Potential Groundwater Recovery Location

NRG is therefore planning a groundwater recovery project that will capture and reuse water from the Powell Bay Area Rapid Transit location. This project is expected to meet 40% to 60% of the total NRG system boiler feedwater consumption annually.

Additional groundwater reuse from the Central Subway and Transbay recovery sites should be studied to further reduce the systems' use of potable water.

3.5 Recycled Water

Upon maximizing condensate recovery, recycled water can be used in lieu of potable water for boiler feedwater in district steam systems. Similarly, in district cooling and power schemes, recycled water can be used in lieu of potable water for cooling tower makeup purposes.

The availability and pricing of "purple pipe"[8] in the vicinity of the generation plants will to a large degree dictate the feasibility of this strategy, and a "green energy customer" scheme similar to the one discussed for biogas supply should be explored if costs are prohibitive. Though typically of high quality, locally available recycled water standards should also be checked against the operating chemistry requirements of existing district schemes.

3.6 Boiler Flue Heat Recovery $ B F

Flue heat recovery is a common strategy used to increase overall boiler plant thermal efficiency. Flue heat recovery can take various forms given varying boiler plant configurations, but it

[8] Industry term for pipe carrying recycled water.

essentially entails the capture and reuse of heat that would otherwise be exhausted through a flue to the atmosphere.

In steam systems, boiler feedwater economizers and/or direct-contact-type heat exchangers can be installed to capture and reuse waste heat for feedwater preheating. Similarly, in hot water systems this heat can be captured and used to preheat return water before it is recirculated to boilers.

Operators of existing district heating systems will need to assess the spatial and financial feasibility of adding a flue heat recovery system if one does not already exist. This will typically be a straightforward exercise and, if space allows, one that will likely yield a favorable outcome.

CHAPTER 4:
Miscellaneous Strategies

This section summarizes a collection of miscellaneous strategies that do not fall under the CIRE or the energy and resource efficiency category.

4.1 Policy and Code

$ B F

Policy makers are moving toward greater energy efficiency, resiliency, and independence standards. Legislation such as the Local Energy Supply and Resiliency Act and President Obama's executive order to accelerate investment in CHP offers opportunities not only for the development of new district energy schemes, but also for the improvement of existing schemes. In support of such legislation, the Obama administration is engaging with states, industrial companies, utilities, and other stakeholders to encourage policies and programs to increase implementation of district energy. There will therefore be opportunities for district energy providers to voice their opinions and engage in the process.

CIRE systems will undoubtedly play a central role in these improvement investments. District energy providers should therefore consider how policy and code forces could make integrating CIRE systems into existing district energy schemes more attractive. Aspects such as interconnection rules, financial incentives, standby rates, net metering, and portfolio standards can all be leveraged to improve district energy and CIRE feasibility, while also helping policy makers reach their goals.

4.2 Education and Outreach

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District energy is still a relatively unknown and poorly understood concept among typical building owners, occupants, and financiers. This makes it difficult not only for design teams to include district energy as the basis of design in new projects, but also for financial modelers and financiers to develop and sell the district energy business case. Lenders and loan underwriters are also subsequently more hesitant to finance district energy projects given the lack of precedence within their local sphere of influence.

Development of white papers, case studies, and financial modeling templates supporting district energy can empower these decision makers with the tools they need to understand and capture the benefits of district energy. Such tools should be developed not only for new building projects, but also for existing buildings that could potentially connect to a district energy scheme.

A collection of such strategies could be made part of a marketing campaign for existing district energy schemes to enlist new customers, as well as a reference for new schemes to attract anchor loads. Either way, they represent a low cost and highly feasible way in which to cultivate a bottom up district energy acceptance culture.

4.3 Community Amenities

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Integrating district energy with community amenities can spread awareness about the benefits of district energy. Where such integration already exists, district energy operators can seek out relatively low-cost opportunities to make the district energy supply story more transparent and well communicated within the local community. This could entail strategies ranging from signage and promotional posters to plant room and building interconnection tours.

Where such integration does not exist, district energy providers should seek out the most transparent integration opportunities that can serve as instant reminders of a community-level energy system. Energy end uses discussed at the workshop included the following:

- community pool heating
- basketball and/or sport court lighting
- power and heating for public assembly spaces
- rooftop decks and/or green roofs enabled by elimination of building-level thermal equipment

GLOSSARY

Term	Definition
CCSF	City and County of San Francisco
CHP	combined heat and power
CIRE	Community Integrated Renewable Energy
CO_2	carbon dioxide

REFERENCES

Article 5, Sections 95800 to 96023, Title 17, California Code of Regulations.

APPENDIX C:
Task 2: Community-Distributed Generation (Technical and Cost Impact Report)

Energy Research and Development Division
FINAL PROJECT REPORT

COMMUNITY INTEGRATED RENEWABLE ENERGY PROJECT

Task 2: Community-Distributed Generation (Technical and Cost Impact Report)

Prepared for: California Energy Commission
Prepared by: Arup, for the San Francisco Department of Environment

ARUP

FEBRUARY 2014
CEC-500-2014-FEB

CHAPTER 1: Introduction

1.1 Project Description

The CIRE project will assess the feasibility of community-based energy, integrating district heating and cooling, renewable electricity, storage and energy recovery, demand response, and smart distribution technology to serve members of a community with their energy needs.

The CIRE Project consists of the following reportable tasks:

- Task 1: Administration and Reporting
- Task 2: Distributed Generation Connected to the Electricity Network
- Task 3: Enabling Technologies
- Task 4: Energy Storage and Generation
- Task 5: District Thermal Energy Concept

This report provides our preliminary findings into Task 2: Distributed Generation Connected to the Electricity Network. The goal of this task is to assess the technical requirements and cost implications of enabling increased penetration of renewable DG into the electricity network, and increasing CIRE projects in California generally, and San Francisco's Central SoMa neighborhood specifically.

This report investigates the technical limitations and cost impacts of increasing the amount of DG on the electric distribution network through the following methods:

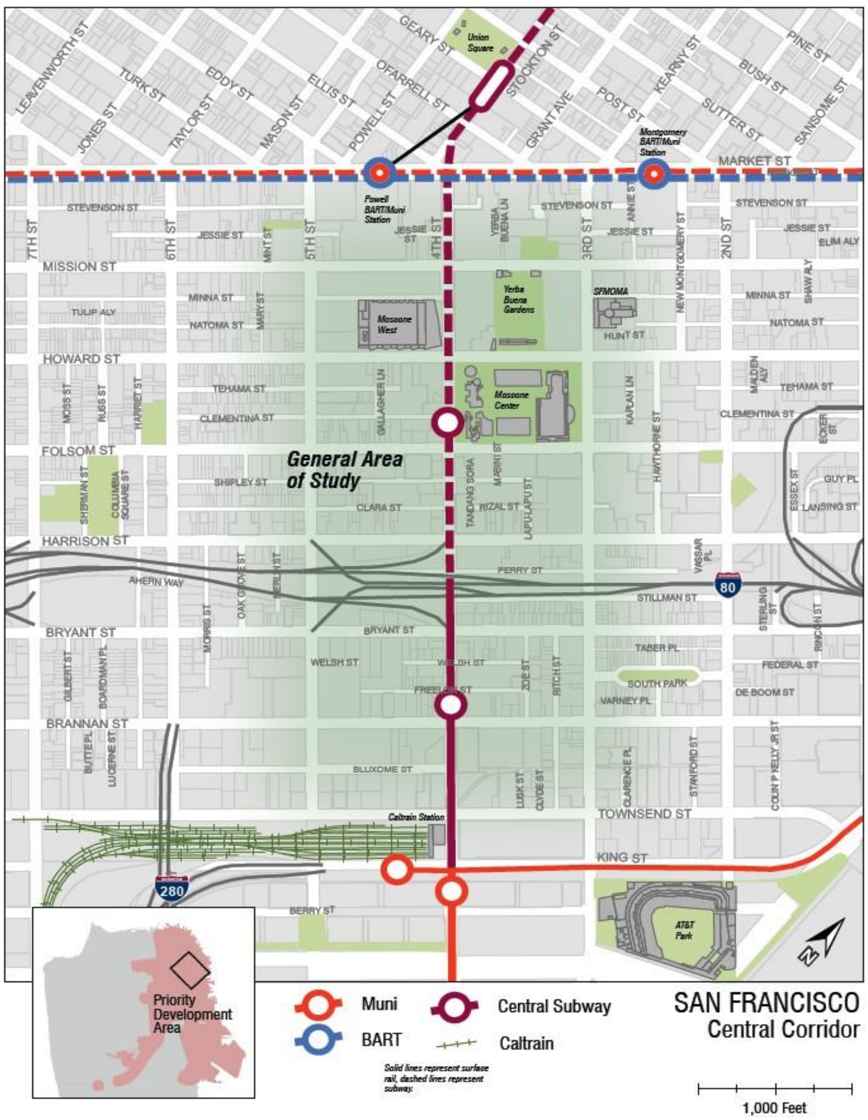
- reporting and mapping where network modifications are required in San Francisco's Central SoMa, providing data that is specific to San Francisco but applicable to other California distribution networks;
- reporting on PG&E's technical engineering concerns about increasing renewable technology within an urban electricity distribution system;
- presenting economic estimations for the works required to facilitate large-scale renewable penetration in urban distribution systems, which may be used as a guide/benchmark to inform other projects within California.

1.2 Central SoMa

In San Francisco, 56% of greenhouse gas emissions are associated with lighting, heating, and cooling buildings. The City and County of San Francisco (CCSF) is committed to developing and implementing aggressive and diversified approaches to reducing these emissions while continuing to absorb anticipated regional population growth. One such approach is to plan carbon-free community-scale energy resources locally and regionally. Another is to increase jobs and housing in transit-oriented neighborhoods.

Central SoMa (South of Market) is a dense, transit-rich area of San Francisco that extends from Second Street to Sixth Street and from Market Street to Townsend Street in the city's South of Market area. The area has been identified as a priority development area by the Planning Department, and is the subject of a significant rezoning effort that encourages sustainable growth and creates substantial opportunities to align energy, transportation, water, and waste infrastructure systems. In addition to identifying the renewable energy resources and enabling technologies that could be appropriate for this district, the CIRE Project will identify ways CCSF can advance community-scale energy in this neighborhood. These efforts include providing a strategy to coordinate multiple public and private interests, including identification of all key institutional stakeholders and relevant regulatory frameworks.

Figure 1: San Francisco Central SoMa



Source: City and County of San Francisco

With the addition of the Central Subway along and under Fourth Street (now under construction and scheduled to begin operation in 2018), undeveloped or underdeveloped parcels in the transit corridor offer a major development opportunity. CCSF anticipates approximately 10,000 new housing units and 35,000 jobs in this area. The Central SoMa Plan, released in draft in April 2013, proposes rezoning this area for dense, transit-oriented, mixed-use growth and provides opportunities to capitalize on rezoning to incorporate district-level energy infrastructure.

In addition to providing local energy, creating CIRE projects will greatly enhance the resiliency of Central SoMa. The ability to generate power and provide local energy for such services as producing potable water and treating sewage is essential for both the immediate and long-term recovery from a large earthquake or similar disaster.

The Central SoMa CIRE Project has the potential to inform similar planning efforts in other parts of the state, particularly those with new development areas, major infrastructure projects, or significant revitalization planned, as well as existing, mature neighborhoods.

1.3 Community Integrated Renewable Energy

California leads the country in the deployment of renewable generation. California law requires state utilities to procure 33% of their electricity needs from eligible renewable resources by 2020. This policy is called the Renewable Portfolio Standard (RPS).

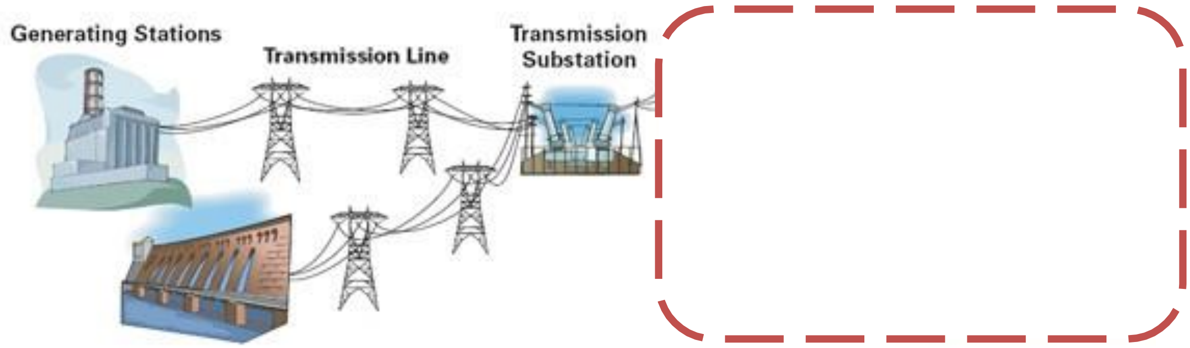
As a next step aimed at raising even further the State's ambitious renewable energy targets, Governor Jerry Brown has called for 12,000 MW of distributed renewable power to be generated by projects sized no larger than 20 MWs.

While the CEC has been tasked to work on how this target might be allocated amongst various programs and geographic or utility areas, it is broadly expected to include MWs from existing rooftop and ground mount programs, e.g., the California Solar Initiative, Renewable Auction Mechanism, Feed-in Tariffs and general renewable solicitations, etc.

To put the 12,000MW number into perspective, the California Solar Initiative (designed to support installation of solar PV systems under 1MW) has a goal of 1,940MW of installed capacity by 2016 and has currently reached the 1,659MW installed mark via approximately 160,000 installations since the program's launch in 2007 (*Peterson, 2013*). This 1,940MW target does not include publically owned utilities (which the 12,000MW target will apply to), but serves as a useful reference to the amount of renewable energy connections that could be required for small renewable energy systems.

In the context of this report, *local renewable power* is defined as generation installed on the distribution network so that benefits are gained locally. Such benefits include reduced system losses, energy security, deferred need for transmission lines and increased renewable energy content. Often these schemes are installed right at the load point, maximizing these benefits. The projects are typically sized from 1kW to 20MW and can be technologies such as photovoltaics, small wind, and biogas fuel cells. A key feature of CIRE projects is that electricity is generated and distributed within a community, defined in this project as the Central SoMa redevelopment area in the South of Market (SoMa) neighborhood in San Francisco.

Figure 2: Location of CIRE Projects



Source: Southern California Edison (SCE)

Implementing CIRE projects will provide important advantages in California's drive for clean power — development of local resources, avoided costs of new intercity transmission or remote generation, additional consumer autonomy, greater resiliency and reduced greenhouse gas emissions.

Local community generation drastically shortens the distance between the source location where energy is generated and the site where it is being used. This system reduces the need for high voltage transmission infrastructure upgrades, as well as reduces the amount of energy being lost from source to site. The reduced reliance on large combustion based centralized generation for energy needs will also lead to a significant reduction of carbon dioxide emissions, which is required in several government programs.

This report aims to identify cost and technical barriers to deploying DG on the distribution network.

This paper considers the following scenarios:

1. Standard Distribution Network
    a. 100kW generation connection
    b. 500kW generation connection
    c. 1MW generation connection
    d. 10MW generation connection
2. Low-Voltage Secondary Distribution Network
    a. Low voltage generation connection

CHAPTER 2: Interconnection

Every CIRE project will have a connection to the wider electricity grid and will therefore be required to obtain an interconnection.

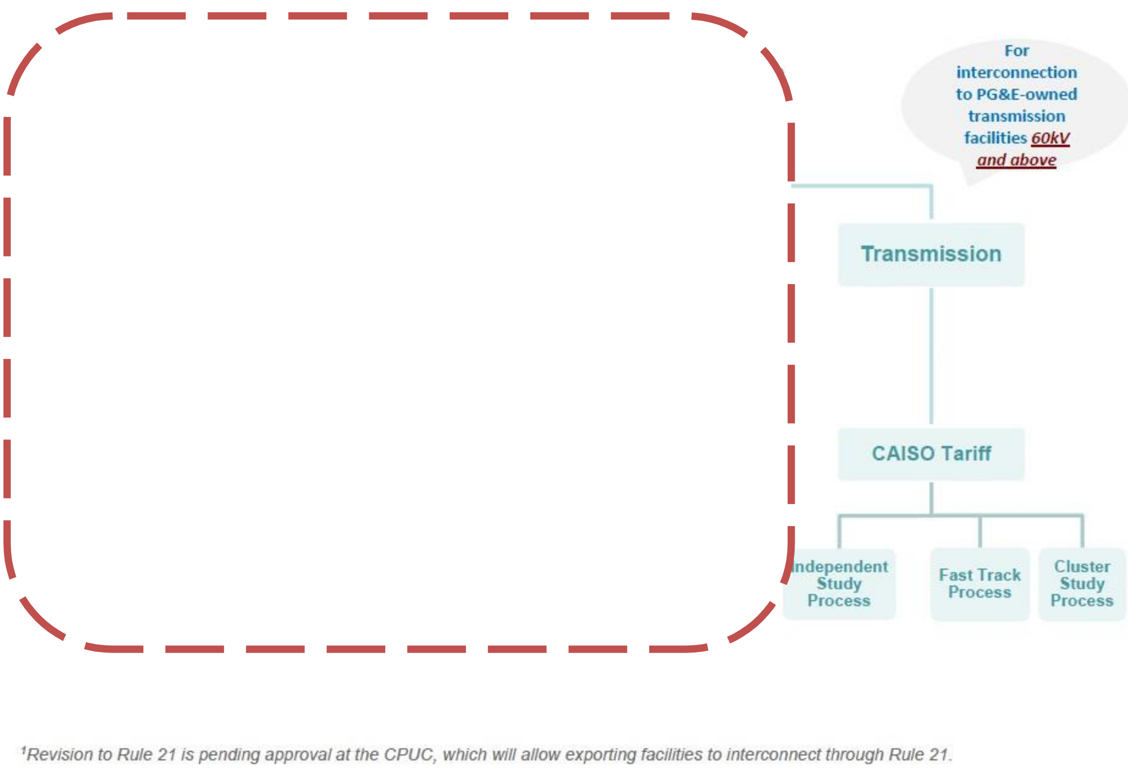
This section defines the various interconnection options suitable for a CIRE project. The definition of the interconnection process is important in understanding the rate at which the generation asset will receive bill credits or direct payments and will play a part in the project's economic performance.

2.1 Overview

CIRE projects by their very definition involve communities. Communities contain businesses, residential homeowners and tenants, and other electricity consumers such as public facilities, neighborhood services and recreational facilities that make up a community. CIRE projects will always connect to the utility grid at the distribution level by virtue of their location, and would typically be under 20MW, and therefore would count towards Governor Browns 12,000MW local renewable energy goals.

Figure 3 shows the interconnection options that are available to CIRE projects.

Figure 3: Generator Interconnection



Source: PG&E

2.2 Electric Rule 21

At the community scale, Electric Rule 21 (“Rule 21”) is likely to be the interconnection option applicable to the majority of CIRE projects.

Rule 21 is a set of regulations that describes the interconnection, operation, and metering requirements for distributed generators to be connected to a utility’s electric system. The CPUC has jurisdiction over the Electric Rule 21 tariff. The Rule 21 tariff and the related CPUC-approved interconnection agreements are generally the same for each of California’s IOUs.

Within Rule 21 there are various paths that can be taken to interconnect generation, with increasing studies and fees required for larger generators, and a more streamlined option for smaller generators. There are both retail and wholesale energy contracts available within Rule 21.

Rule 21 applies to generators that fall into one of the below categories:

- generate power for the applicant’s own retail use only and do not export power to the electric grid (“non-export”);
- generate power for the applicant’s own use and for export to the electric grid for credit on their retail PG&E bills;
- operate as qualifying facilities, as defined by the FERC’s Public Utility Regulatory Policy Act (PURPA), that sell (or export) all of their energy to the grid for sale to a California IOU through a wholesale PURPA Power Purchase Agreement (PPA).

2.2.1 Net Energy Metering

Net energy metering (NEM) is a renewable energy billing arrangement that currently allows customers with eligible DG to credit the DG system’s electricity production against their on-site electricity use over the course of a month, even if the system primarily exporting (such as with a residential solar system during the day), and thus receive compensation for the electricity their DG system generates at the full retail value of the electricity use it offsets. Under NEM, when the installed DG produces more electricity than the customer demand, the excess energy automatically exports to the utility grid. Customers that generate a net surplus of energy at the end of a 12-month period can receive a payment for this energy under special utility tariffs.

NEM is available for systems of up to 1MW in size. For generation systems that are greater than 1MW in size, the customer has the option under the Rule 21 tariff to install the first MW of generation under the NEM agreement, being compensated at the full retail rate for exported energy, and the remaining generation as non-NEM generation, which may be compensated for at a lower wholesale value of the generated exported energy.

2.3 Wholesale Distribution Tariff

All wholesale generator distribution interconnections are governed by the IOU's wholesale distribution tariff (WDT).

There are several types of wholesale generation interconnection options:

- Distribution – projects that interconnect with a utility's distribution system, generally at a voltage level below 60 kilovolts (kV). These projects are governed by a WDT and are likely to be a suitable interconnection vehicle for CIRE projects.
- Transmission – projects that interconnect at a voltage level of 60kV or higher. These projects are governed by a CAISO tariff. It is not expected that this interconnection vehicle will be suitable for CIRE projects.
- Qualifying facilities – facilities that interconnect with a utility's transmission or distribution system, producing wind, hydroelectric, biomass, waste, or geothermal energy and sell energy to utilities at a wholesale rate. Qualifying facilities can also be cogeneration facilities that produce electricity and another form of thermal energy, and may be suitable for certain types of CIRE projects.

2.4 Summary and Fees

All utility interconnection processes have defined response timelines and options for fast track or detailed studies depending on the rating of the renewable generation being connected. Table 1 provides a summary of the various interconnection fees and required studies relevant to CIRE projects.

Table 1: Interconnection Summary

	Rule 21 <1MW	**Rule 21 >1MW**	**WDT**
MW Limit	1MW	None	None
Application Fee	$800	$800	$800
Fast Track Process Limits	Generators under 1MW typically follow a fast track process	≤3MW	≤2MW on 12kV ≤3MW on 21kV ≤5MW on higher voltages
System Impact Study (5MW or less)	N/A	Required, with $10k deposit	Required, with $10k deposit
Facilities Study	N/A	Required, with $15k deposit	Required, with $15k deposit
System Impact Study (>5MW)	N/A	Required, with $50k + $1k/MW (maximum of $250k) deposit	Required, with $50k + $1k/MW (maximum of $250k) deposit

The study deposits are used to cover prudent costs incurred by the utility to perform and administer the interconnection studies. Should the prudent costs be less than paid by the applicant, the provider shall refund the difference to the applicant.

CHAPTER 3:
Distribution Networks

In California, there are two predominant methods that utilities use to distribute power to customers:

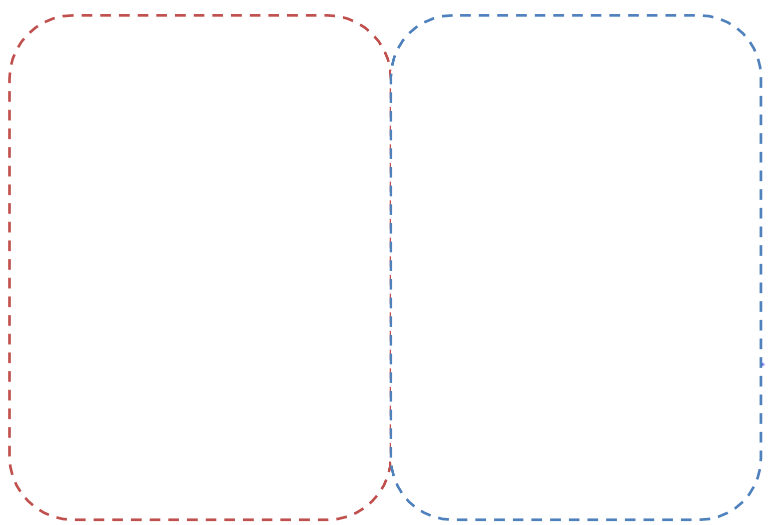
- radial networks – common and simple distribution topology
- secondary networks – uncommon and complex distribution topology

A radial distribution network is the most common type of distribution network, while a secondary distribution network topology provides a far greater level of resilience for low-voltage customers. Examples of areas in California with secondary distribution networks are Los Angeles, Oakland, Sacramento, and San Francisco.

3.1 Radial Distribution Network

Radial distribution systems are the most common design used by electric utilities in California and other parts of the United States. Two types of radial utility distribution systems are depicted in the Figure 4.

Figure 4: Standard Radial Distribution Networks



Source: National Renewable Energy Laboratory (Coddington, Kroposki, & Basso, 2009)

The first example, outlined in red in Figure 4, is a standard radial feed. The utility distributes power to customers via step-down transformers. Power will generally be distributed by the utility at distribution voltages (15kV class) before being stepped down to serve local customers at low voltage. Should there be a fault on Feeder 1; the customers who are supplied from Feeder 1 would lose power until the fault is rectified.

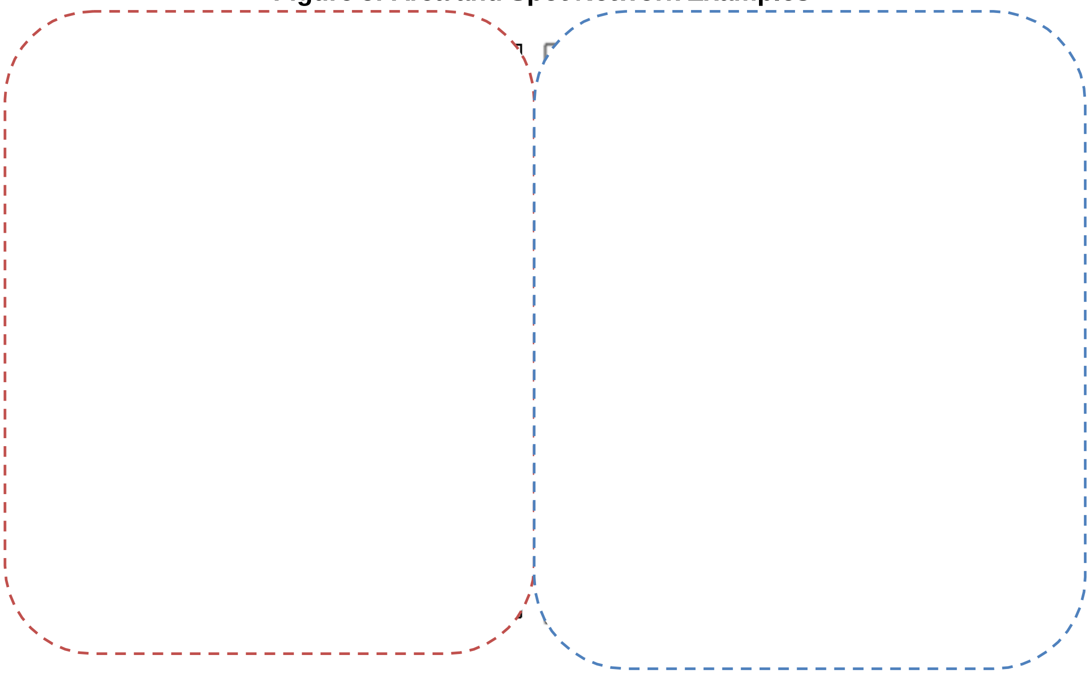
A more secure radial feed is depicted in the second example, outlined in blue. An open loop radial feed provides power to customers. Should Feeder 1 develop a fault, the open switch can be closed (typically automatically) and provide the customers supplied from Feeder 1 with power from an alternative source until the fault is resolved.

3.2 Secondary Distribution Network

3.2.1 Area and Spot Network

In a secondary distribution network, electricity is delivered through a complex and integrated system of multiple transformers and underground cables that are connected and operate in parallel.

Figure 5: Area and Spot Network Examples



Source: National Renewable Energy Laboratory (Coddington, Kroposki, & Basso, 2009)

The two examples in the figures above represent an Area and Spot network. In an area network, highlighted in red, there are multiple customers supplied within the bounds of the defined network. At a point in the network there will be load draw from multiple customers. A spot network on the other hand, highlighted in blue, supplies one customer. The customer is still supplied via multiple supply points for a similar level of resilience but there is no other demand from other customers on the particular branch of the spot network.

Due to the inbuilt redundancy in a secondary network, should a fault develop on an underground feeder or even a transformer, a customer would see no interruption in power as power would immediately flow from another part of the secondary network. Each customer within a secondary network has multiple levels of failure that can occur before the customer experiences a power loss.

A very important feature of secondary networks is the type of protection that they employ. In secondary networks, devices called *network protectors* are used to prevent power from back-feeding from one transformer through another. A network protector is designed to open and stop power flow in the event that back-feeding of power is detected. The network protector is an important design feature that ensures reliability and continuous operation of the secondary network if one or more feeders are lost by isolating the faulty section and making the network safe for repair workers. Network protectors may also open during light-loading conditions, which can occur on secondary networks at certain times of the year. Secondary networks are designed to have a certain load flowing through the protectors from the utility to the customer.

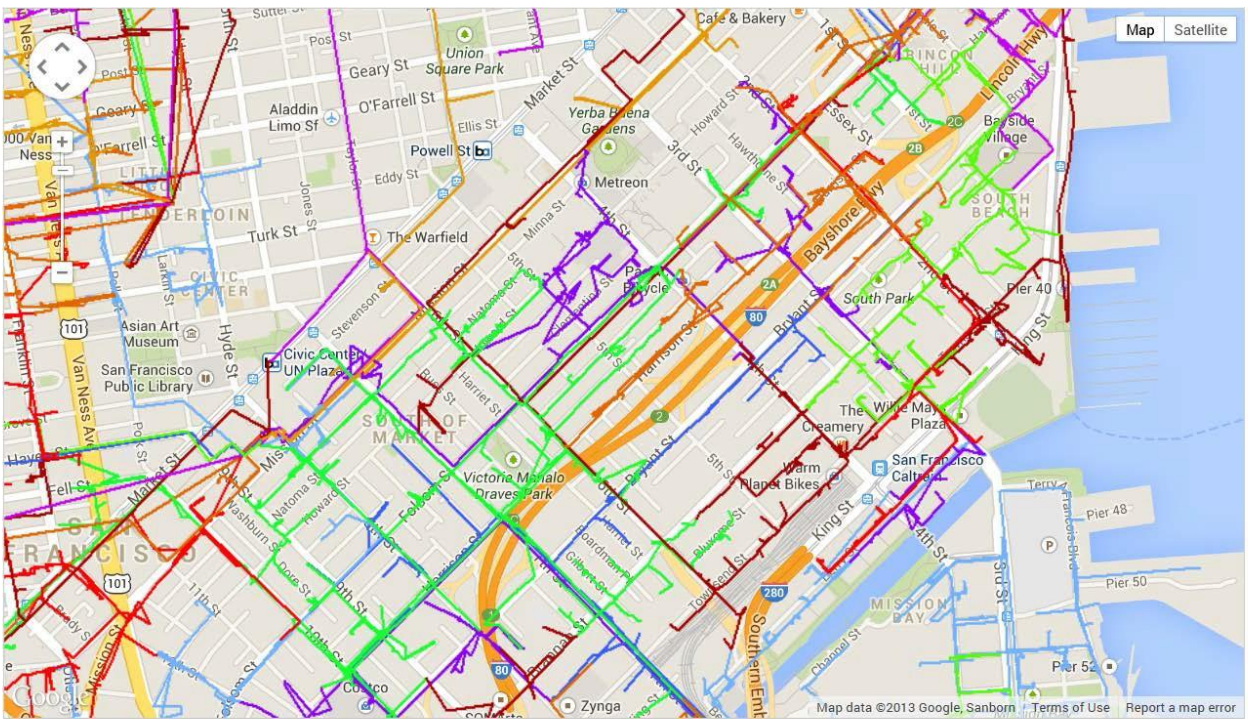
3.3 Utility Mapping

During the development of the Renewable Auction Mechanism, the CPUC dictated that California IOUs prepare network maps showing the utility distribution network. The maps identify basic network parameters to assist developers in connecting DG in an IOU's service territory. The primary purpose of the mapping is to allow developers to select suitable generation locations that avoid lengthy interconnections due to required network upgrades. The maps form a useful first reference for a developer before formal communication between the developer and the IOU is established.

The maps show the high-voltage transmission lines, medium-voltage distribution lines, and substations, and do not identify low-voltage assets. The maps are aimed primarily at distribution-connected renewable generation assets that will connect to PG&E via a wholesale interconnection tariff.

According to the available maps, all distribution assets in Central SoMa are identified in Figure 6.

Figure 6: PG&E Distribution Network in Central SoMa



Source: PG&E[2]

2 Accessed from https://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/PVRAMMap/index.shtml (individual log-in required)

Users can access data on a selected individual distribution feeder by accessing these maps online and clicking the feeder in the Central SoMa area (Figure 7).

Figure 7: Network Capacity Results

Longitude: -122.402759, Latitude: 37.782282

Total # of Results:1

Result #1: *SF X 1102*

From layer: Distribution Lines

DIVNAME	SAN FRANCISCO
SUBNAME	MISSION
SUBNUM	2201
FDRNAME	MISSION 1102
Feeder Number	22011102
Nominal Circuit Voltage (kv)	12
Circuit Capacity (MW)	12.3
Circuit Projected Peak Load (MW)	9.65
Substation Bank	1
Substation Bank Capacity (MW)	75
Substation Bank Peak Load (MW)	55
Existing Distributed Generation (MW)	0.2078
Queued Distributed Generation (MW)	0
Total Distributed Generation (MW)	0.2078

Source: PG&E[3]

The selected feeder has a small amount of renewable generation connected on the feeder when compared to the feeder's peak load. The connected generation totals 208kW and the feeder's peak load is 9.65MW, or 46 times greater. The estimated minimum load (15% of peak) is 1.4MW. The results also dictate how many other renewable projects are in the interconnection queue for this particular feeder, of which there are none as of October 2013.

[3] Accessed from https://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/PVRAMMap/index.shtml (individual log-in required)

Central SoMa does not have a high penetration of installed renewable generation. Of all of the distribution feeders assessed in Central SoMa, none of the feeders minimum loads were exceeded by existing renewable generation. Every feeder assed has the capacity for more renewable generation to be installed. Table 2 details the level of installed renewable generation within Central SoMa.

Table 2: Installed Generation in Central SoMa

Feeder Number	Feeder Peak Load (MW)	Feeder Minimum Load (15% of Maximum) (MW)	Current Installed Generation (MW)	New Generation Capacity before Upgrades are Required[4] (MW)
22011102	9.7	1.4	0.2	1.2
22011111	6.1	0.9	0.0	0.9
22031113	6.2	0.9	0.3	0.6
22031115	5.9	0.9	0.5	0.4
22871115	2.8	0.4	0.1	0.4
22871116	12.0	1.8	0.1	1.7
22871117	7.6	1.1	0.0	1.1
22871118	9.9	1.5	0.0	1.5
22871119	10.4	1.6	0.1	1.4
22871122	8.1	1.2	0.0	1.2
22871121	7.0	1.0	0.0	1.0
22011101	3.7	0.6	0.0	0.6

Based on the above results, none of the feeders require modification to allow further generation capacity to be installed on the feeders. Individual feeders may have other criteria for modification other than a minimum load exceedance and this would be required to be discussed with the utility on a case-by-case basis. The utility mapping described in this section

[4] Exceeding the feeders minimum load has been used as a requirement for the potential of required circuit upgrades. Depending on the generation technology installed and the particular feeder, it may be possible to install more generation on a particular feeder before any upgrades are necessary.

does not include the secondary network which is subject to much more onerous generation interconnection requirements.

3.4 Pre-application

During the feasibility process of a particular renewable energy project, within California there is a low cost method of determining if an interconnection is going to be cost prohibitive. In California developers can request a pre-application report to allow the developer to determine the likely interconnection costs. Previously, developers would have to submit an interconnection request and go through the early stages of the interconnection process to determine costs.

The pre-application report is $300 and allows developers to obtain the following information from the relevant utility:

- Total capacity and available capacity of the facilities that serve the point of interconnection
- Existing and queued generation at the facilities likely serving the point of interconnection
- Voltage of the facilities that serve the point of interconnection
- Circuit distance between the proposed point of interconnection and the substation likely to serve the point of Interconnection
- Number and rating of protective devices, as well as number and type of voltage-regulating devices between the proposed point of interconnection and the substation
- Number of phases available at the proposed point of interconnection
- Limiting conductor ratings from the proposed point of interconnection to the substation
- Peak and minimum load data
- Existing or known constraints associated with the point of interconnection

CHAPTER 4: Interconnection Cost Estimates

In order to understand if interconnection costs are a barrier to renewable energy development within Central SoMa, PG&E has provided case studies of typical generation costs within its service territory.

The case studies cover the cost of interconnection equipment that is required to be installed. The costs presented do not include the interconnection fees as described in Section 2.4.

These are general case studies — each individual generator interconnection application has a formal, well-defined generator application process, as defined in Chapter 2. Individual costs will vary, and these costs are provided to indicate a potential order of magnitude for generator connections.

Costs for Over Head (OH) and Under Ground (UG) distribution circuit connections have been provided where applicable in order to present a range of cost options.

This report considers the following scenarios:

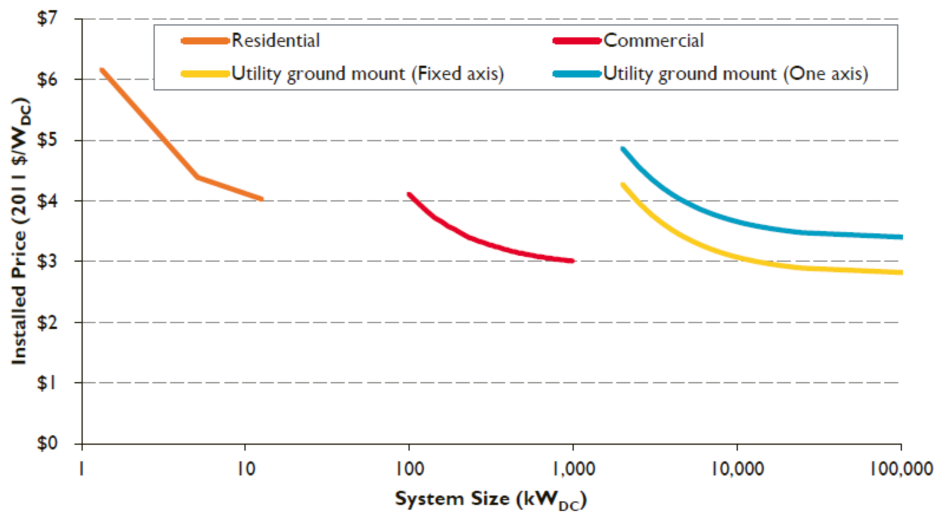
1. Radial Distribution Network
    a. 100kW generation connection
    b. 500kW generation connection
    c. 1MW generation connection
    d. 10MW generation connection
2. Low-Voltage Secondary Distribution Network
    a. Low voltage generation connection [5]

When reviewing the costs of interconnections, it is necessary to benchmark the interconnection costs against the total renewable generation project costs in order to assess if the interconnection cost represents a significant economic barrier. If interconnection costs are above 10% of a total project cost, then this may, depending on the particular project's business case, make the project uneconomical for construction. The economics of a particular project are highly site specific and a project's economics require investigating on a case-by-case basis to determine if a particular interconnection cost deems a project uneconomical.

[5] In the secondary networks the generator must be sized in relation to the building load. The generation is typically sized as a percentage of the buildings minimum load.

In order to compare the costs of various interconnections to the cost of renewable generation, PV has been selected as the benchmark comparison cost. This is due to the large amount of cost data available for this mature market and the fact that the generation type is ideally suited to California's climate and urban CIRE projects. Figure 8 presents typical installed costs for grid-connected PV systems.

Figure 8: Installed PV Costs



Source: National Renewable Energy Laboratory, 2012 (Feldman, Barbose, & Margolis, 2012)

For this report, the costs identified in Table 2 have been used to estimate PV system costs. Costs are presented in Watts (W) on the Direct Current (DC) side of the generation asset.

Table 3: PV System Costs

PV System Size	Cost ($/W$_{DC}$)
1 – 4 kW (Residential)	6.2
4-10 kW (Residential)	4
4-100kW (Commercial)	4
>1MW (Commercial)	3
>10MW (Utility) (fixed axis)	3

The remainder of this section provides case study interconnection cost estimates for both the radial feed networks and secondary networks.

4.1 Radial Feed Network

The examples within this section all assume that the generation source will connect to the utility distribution grid either directly or indirectly via a customer service.

4.1.1 100kW Generator Connection

The costs presented in this section are for a 100kW DG interconnection on a normal distribution feeder. This option assumes that the customer is connected on the secondary side (low voltage) of a PG&E-owned distribution transformer. The generation is expected to have a maximum connection voltage of 480V.

Table 4: 100kW Interconnection Cost

	Secondary service	**Cost**
Distribution Circuit Upgrades	Visible disconnect switch	$5,000
	PG&E secondary revenue metering	$5,000
TOTAL		$10,000
Typical total system cost		$400,000

This interconnection option has a typical cost in the order of $10,000. A PV installation of this size including all balance of materials is expected to cost in the order of $400,000. A $10,000 interconnection cost represents 2.5% of the system cost and is not expected to make this installation uneconomical.

4.1.2 500kW Generator Connection

Two case studies are presented in this section, which represent options for a 500kW DG interconnection on a normal radial distribution feeder.

The options presented relate to the relationship between the peak load upon a feeder and the size of the generation. The online utility interconnection maps provide a first point of reference to quickly determine the peak feeder load on the feeders in the vicinity of a proposed DG project.

The first option assumes that there is an overhead/underground three-phase service to the generator and the total installed generator capacity represents less than 15% of the line section peak load.

Table 5: 500kW Interconnection Cost – DG <15% of Peak Load

	Secondary service	Cost
Distribution Circuit Upgrades	Visible disconnect switch	$25,000
	PG&E primary revenue metering	$15,000
	Primary service (OH - UG)	$15,000–$45,000
TOTAL		$55,000–$85,000

This interconnection option has a typical cost in the order of $55,000 to $85,000. A PV installation of this size including all balance of materials is expected to cost in the order of $2,000,000. A $55,000 to $85,000 interconnection cost represents 2.75% to 4.35% of the system cost and is not expected to make this installation uneconomical.

This second 500kW option assumes that the installed DG size represents a greater capacity than 15% of the line section peak load. In addition, specific locations may require normally optional distribution circuit upgrades. The need for these upgrades is site dependent and can be determined only in consultation with the connecting utility.

Table 6: 500kW Interconnection Cost – DG >15% of Peak Load

	Secondary service	Cost
Distribution Circuit Upgrades	Pull third phase if single line tap (OH)	$85/feet
	Pull third phase if single line tap (UG)	$105/feet
	Visible disconnect switch	$25,000
	Ground fault detection (primary interconnection)	$45,000
	Primary service (OH - UG)	$15,000–$45,000
	PG&E primary revenue metering	$15,000
TOTAL (excluding third phase)		$100,000–$130,000

The cost estimation for this option when the generation rating is sized at over 15% of the line load is heavily dependent on the cost of any required conductor upgrades. Sites near the connection point will have a much lower cost. For example, if a site is within 500ft of the utility connection, the total interconnection cost is $142,500 to $172,500. Extending this to a mile (5,280ft) increases the interconnection cost to $654,400 to $684,400. A PV installation of this size including all balance of materials is expected to cost in the order of $2,000,000. These two distance options represent a range of interconnection costs as a percentage of the total project costs of 7% to 8.6% and 32% to 34%.

There is the potential for upgrade requirements to inhibit renewable generation in this scenario. The interconnection costs can potentially be a large component of the system costs. Should conductor upgrades be required, the distance between the generator and the interconnection point will determine the viability of such an interconnection.

4.1.3 1,000kW Generator Connection

This section presents three case studies that represent options for a 1,000kW DG interconnection on a normal distribution feeder.

The options presented relate to the relationship between the peak load upon a feeder, the size of the generation, and whether the DG exports energy to the distribution system. The online utility interconnection maps provide a first point of reference to quickly determine the peak feeder load on the feeders in the vicinity of a proposed DG project.

The first option assumes that the proposed DG is the only DG on the circuit and that there is a three-phase service to site with generation representing less than 15% of line section peak load.

Table 7: 1,000kW Interconnection Cost – DG <15% of Peak Load

	Secondary service	**Cost**
Distribution Circuit Upgrades	Visible disconnect switch	$25,000
	Install recloser for visibility	$65,000
	Primary service (OH, UG)	$15,000–$45,000
	PG&E primary revenue metering	$15,000
TOTAL		$120,000–$150,000

This interconnection option has a typical cost in the order of $120,000 to $150,000. A PV installation of this size including all balance of materials is expected to cost in the order of $3,000,000. A $120,000 to $150,000 interconnection cost represents 4% to 5% of the system cost and is not expected to make this installation uneconomical.

This second option assumes that there is a fuse on the line section and there is also other DG on the circuit. This option assumes that the site does not export past the feeder circuit to which the DG is installed.

Table 8: 1,000kW Interconnection Cost – Other DG

	Secondary service	Cost
Distribution Circuit Upgrades	Install reclose blocking on line recloser	$10,000/unit
	Visible disconnect switch	$25,000
	Replace all line fuses with three phase interrupting devices	$100,000-interrupter or $65,000-recloser
	Ground fault detection	$45,000
	Install recloser for visibility	$65,000
	Primary service (OH, UG)	$15,000–$45,000
	PG&E primary revenue metering	$15,000
TOTAL (one recloser)		$144,500–$174,500

This interconnection option has a typical cost in the order of $144,500 to $174,500. A PV installation of this size including all balance of materials is expected to cost in the order of $3,000,000. A $144,500 to $174,500 interconnection cost represents an additional 4.8% to 5.8% cost to the system and is not expected to make this installation uneconomical.

This third option assumes that there are fuses on the line section with DG back-feeding permitted through the DG feeder circuit breaker but not through the substation transformer. This means that all energy produced on the utility feeder must at all times be consumed by the local distribution system and not back-feed the distribution system via the substation step-up transformer.

Table 9: 1,000kW Interconnection Cost – Export to Distribution Circuit

	Secondary service	Cost
Distribution Circuit Upgrades	Install recloser block at circuit breaker	$80,000
	Install reclose blocking line recloser	$10,000/unit
	Visible disconnect switch	$25,000
	Replace all line fuses with three phase interrupting devices	$100,000-interrupter or $65,000-recloser
	Ground fault detection	$45,000
	Install recloser for visibility	$65,000
	Regulator (voltage fluctuation)	$100,000
	Primary service (OH)	$15,000–$45,000
	Replace old mechanical relay with microprocessor based relay	$100,000
	PG&E primary revenue metering	$15,000
TOTAL		$555,000–$585,000

This interconnection option has a typical cost in the order of $555,000 to $585,000. A PV installation of this size including all balance of materials is expected to cost in the order of $3,000,000. A $555,000 to $585,000 interconnection cost represents 18.5% to 19.5% of the system costs and may make this installation uneconomical.

4.1.4 10,000kW Generator Connection

The section presents three case studies that represent options for a 10,000kW DG interconnection on a normal distribution feeder.

The options presented relate to whether the system exports energy to the local distribution system, whether the system exports energy to the wider distribution system (past the substation transformer), and whether the existing utility substation transformers are overloaded. The online utility interconnection maps provide a first point of reference to quickly determine the peak feeder load on the feeders in the vicinity of a proposed DG project.

This first option assumes that no substation transformers are overloaded. It is assumed that three phase-interrupting devices exist on the high side of the substation transformer. Export through the circuit breaker supplying the DG is acceptable; however, export past the utility transformer is not permitted.

Table 10: 10,000kW Interconnection Cost – Export to Distribution System

	Secondary service	**Cost**
Distribution Upgrades	PG&E control and monitoring testing for visibility	$120,000
	Install direct transfer trip from substation to DG site (not needed for PV or dedicated feeder)	$250,000
	Install recloser block at circuit breaker	$80,000
	Install recloser block at line reclose	$10,000/unit
	Replace all line fuses with three phase interrupting devices	$100,000-interrupter or $65,000-line recloser
	Re-conductoring smaller conductor (OH)	$85/feet
	Re-conductoring smaller conductor (UG)	$105/feet
	Replace old mechanical relay with microprocessor based relay	$100,000
	Regulator (voltage fluctuation)	$100,000
	Visible disconnect switch	$25,000
	Ground fault detection	$45,000
	Primary service (OH, UG)	$15,000–$45,000
	PG&E primary revenue metering	$15,000
TOTAL (Excluding re-conductoring)		$860,000–$890,000

The cost estimation for this option is somewhat dependent on the cost of any required upgrades due to re-conductoring. Sites near the interconnection point will have a lower cost. For example if a site is within 500ft of the interconnection, the total interconnection cost is $912,500 to $942,500. Extending this to a mile (5,280ft) increases the interconnection cost to $1,414,400 to $1,444,400. A 10MW solar array is expected to have a total project cost including balance of materials of $30,000,000. These two interconnection distance options represent a range of interconnection costs as a percentage of the total project costs of 3% to 4.8%. These interconnection costs are not expected to inhibit renewable energy development at this scale.

This second option assumes that the substation transformer has no overloading conditions and that the existing high side is protected by fuses. Export of the power past the substation transformer to the wider distribution network is acceptable in this scenario.

Table 11: 10,000kW Interconnection Cost – Export past Distribution System

	Secondary service	Cost
Network Upgrades	Replace high side fuse with circuit breaker	$1,000,000
	DTT may be required from the transmission line	$250,000/unit
Distribution Upgrades	Replace old mechanical relay with microprocessor based relay	$125,000
	PG&E control and monitoring testing for visibility	$120,000
	Install recloser block at circuit breaker	$80,000
	Install recloser block at line reclose	$10,000/unit
	Replace all line fuses with three phase interrupting devices	$100,000-interrupter or $65,000-line recloser
	Re-conductoring smaller conductor (OH)	$85/feet
	Re-conductoring smaller conductor (UG)	$105/feet
	Regulator (voltage fluctuation)	$100,000
	Visible disconnect switch	$25,000
	Ground fault detection	$45,000
	Primary service (OH)	$15,000–$45,000
	Line regulator	$100,000
	PG&E primary revenue metering	$15,000
TOTAL (Excluding re-conductoring)		$1,985,000–$2,015,000

The cost estimation for this option is somewhat dependent on the cost of any required upgrades. For example if a site is within 500ft of the connection the total interconnection cost is $2,037,500 to $2,067,500. Extending this to a mile (5,280ft) increases the interconnection cost to $2,539,400 to $2,569,400. A 10MW solar array is expected to have a total project cost including balance of materials of $30,000,000. These two distance options represent a range of interconnection costs as a percentage of the total project costs of 6.9% to 8.5%, and the economic impact of the interconnection costs may be significant. This impact would depend on the particular project.

The final option assumes that the substation transformer is overloaded. This option assumes that the project would be required to procure a new distribution transformer to permit an interconnection.

Table 12: 10,000kW Interconnection Cost – Transformer Upgrade

	Secondary service	Cost
Transformer Bank Size	Replace the transformer bank	$4,500,000 for Banks ≥30 MW
	Replace high side fuse with circuit breaker	$1,000,000
Check with Transmission Protection	DTT may be required from the transmission line	$250,000
Distribution Upgrades	Replace old mechanical relay with microprocessor based relay	$125,000
	PG&E control and monitoring testing for visibility	$120,000
	Install recloser block at circuit breaker	$80,000
	Install recloser block at line reclose	$10,000/unit
	Replace all line fuses with three phase interrupting devices	$100,000-interrupter or $65,000-line recloser
	Re-conductoring smaller conductor (OH)	$85/feet
	Re-conductoring smaller conductor (UG)	$105/feet
	Regulator (voltage fluctuation)	$100,000
	Visible disconnect switch	$25,000
	Ground fault detection	$45,000
	Primary service (OH)	$15,000–$45,000
	PG&E primary revenue metering	$15,000
TOTAL (excluding re-conductoring)		$6,385,000–$6,415,000

The cost estimation for this option is somewhat dependent on the cost of the re-conductoring as the primary cost is for the upgrade of the substation transformers. For example if a site is within 500ft of the connection, the total interconnection cost is $6,437,500 to $6,467,500. Extending this to a mile (5,280ft) increases the interconnection cost to $6,939,400 to $6,969,400. A 10MW solar array is expected to have a total project cost including balance of materials of $30,000,000. These two distance options represent a range of interconnection costs as a percentage of the total project costs of 21% to 23% and are likely to make this interconnection uneconomical.

4.2 Secondary Network

PG&E has very strong technical requirements when placing generation on the secondary network. DG can be connected on the secondary network only behind a customer's meter and used to offset load. PG&E has stated during verbal communications that the rating of the DG must be 10% or less of the customer's estimated minimum load, based on 15 minute measured data to allow renewable generation to be connected without significant study efforts.

Because of the significant barriers to placing DG on the secondary network, the costs for installing protection are limited to relay and protection systems. For a connection to the secondary network, PG&E requires all non-microprocessor network protectors be upgraded with microprocessor relays. PG&E also requires primary and secondary under power relays connected to a separate DC battery system. Finally PG&E requires installation of a controller at each network protector for open/close status to a producer's DG tripping devices. The typical cost for installing this equipment is estimated to be around $40,000.

The key barrier to secondary network deployment in the heart of San Francisco is the requirement for generation to be sized against a 10% of minimum load limit. This small value is a huge constraint to renewable generation in downtown San Francisco, including the northern half of Central SoMa.

The research team has investigated the following solutions for connecting DG to secondary networks and these are described in detail in Section 6.

1. Allow export toward 100% of minimum load for existing buildings with proof of minimum load for several years.

2. Install minimum import relay or a reverse power relay. This can ensure that generation is sized for a more typical building load profile and at the rare times of low load, controls can be installed on the customer side to curtail generation prior to the relay operating.

3. Install dynamic controlled inverter[6] system to follow the building's load to prevent export.

[6] Adding energy storage to this system would allow the excess generation to be stored

CHAPTER 5: Barriers to Large-Scale Renewable Deployment

We have identified the following barriers and break points to community renewable energy development:

5.1 Generation installed that is greater than 15% of a line's peak load

When an installed renewable generator's capacity is over 15% of a line's peak load, there may be a risk of utility network issues occurring.

These challenges that a utility may face include:

- voltage regulation
- islanding risk
- fault contribution risk

The 15% of peak load is an estimate of the *minimum* load of a feeder. The limit is designed to ensure that the generation does not back feed the distribution system at times of high generation output and low load consumption.

Rule 21 interconnection standards provide screens that allow certain sized generation installations to be connected to the utility distribution system without extensive studies. One of the screens for determining this is a determination of the generation capacity compared to the line's peak load.

Up until 2012, Rule 21 stated that a generation scheme can fall under fast track rules should the individual generators rated capacity be less that 15% of the lines peak load.

This rule has now been revised to allow differing screens to be used for PV which only generates during day time hours. Recent updates to Rule 21 include a supplemental maximum capacity screen of 100% of minimum daytime load for the following times:

- 10am – 4pm PV fixed systems
- 8am – 6pm PV tracking systems

Whenever a generation interconnection exceeds 15% of the line's peak load for non-PV generation and 100% of the minimum daytime load for PV generation, it is not automatically determined that the interconnection will be more expensive. The screen limit just requires that utilities do a more in-depth study of the requested interconnection. The study may find that in the particular circumstance being investigated that no distribution system upgrades are required, or it may determine that upgrades such as the upgrades specified in Section 4 are required. Depending on the project size and requirements, this may or may not make the particular case un-economic.

From a technical perspective, again exceeding the Rule 21 limits does not ensure that there are technical issues to be overcome, it just increases the likelihood that an issue may be identified. When the installed generation is a small proportion of the feeder load, the utility concerns such as voltage regulation and fault level are minimal and the utility may be comfortable with connecting the generation with no additional studies / protection requirements. Above this value, the utility will perform detailed studies[7] of the distribution system using the generator details provided by the application. Electrical models will be constructed and the results of the models will determine the requirement of distribution upgrades. These studies are performed on a case-by-case basis and will determine the interconnection costs.

5.2 Generation that requires distribution upgrades / back-feeds a utility transformer

Should a utility's assessment determine that distribution upgrades are required, the cost of these upgrades can inhibit a generation scheme being viable. This barrier is discovered on a case-by-case basis and is subject to the utility's interconnection assessments. The low cost pre-application report available to developers in California is designed to prevent this from happening.

There are ways in which a generation source can avoid these upgrades that are well established. These measures may include:

- Obtain a low cost pre-application report;
- Using utility mapping to determine the peak load of distribution feeders and size appropriately to stay within the utility's screening parameters;
- Using utility load data to ensure that a generation plant does not export power through utility transformers;
- Have pre-application discussion with the utility.

5.3 Generation connection to the secondary network.

The secondary network, due to its configuration of network protectors, has to have a flow of power passing from utility to the final customers. Should there be no power measured, network protectors would operate and isolate areas of the secondary network.

The current preferred PG&E policy to ensure that generation is sized at only 10% of the minimum load is a large barrier to installing generation in Downtown San Francisco. The following section provides some alternative protection topologies that may be installed in San Francisco to increase the renewable energy penetration in the area. The solutions presented are also applicable throughout the secondary networks in California.

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[7] Fees to be paid by the developer as described in Chapter 2

Within San Francisco, should an installation satisfy the 10% minimum load criteria, it means the customer can move forward with the installation without the need of any additional relays, or other equipment that would be required by the utility.

CHAPTER 6:
Potential Solutions

6.1 Generation connected to the Secondary Network.

Within this section we detail solutions that will enable increased penetration of renewable energy in San Francisco's secondary network area. These solutions will also be applicable to other secondary networks in California.

In 2009, NREL completed an assessment entitled "PV Systems Interconnected onto Secondary Network Distribution Systems – Success Stories". The below table summarizes the success stories that were studied by NREL, of which one, the Moscone Center, is located in the San Francisco Spot Network area.

Installation	System Size	Network Type	Protection Installed (Strategy)
Moscone Center, San Francisco, California	676 kWp DC	Spot	Minimum Import Relay
Colorado Convention Centre, Denver, Colorado	300 kWp DC	Spot	Minimum import relay, dynamically controlled inverters
James Forestall Building, Washington, DC	205 kWp DC	Spot	None (minimum load)
Greenpoint Manufacturing and Design Center, Brooklyn, New York	55 kWp DC	Area	None (minimum load)
Big Sue, Brooklyn, New York	40 kWp DC	Area	None (minimum load)
Kinnloch Black Bear, Brooklyn, New York	17 kWp DC	Area	None (minimum load)

6.2 Potential Solutions

6.2.1 Minimum Load Calculation

Using a minimum load calculation to forecast a customer's minimum load for a defined period is a method to allow generation to be installed that does not exceed the premise's minimum load. Meter data in 15 minute increments is gathered for a customer's building for a minimum period of one year. The data is analyzed and the generation system is sized to ensure that the generation output can never exceed the minimum load of the customer.

Under this solution, the interconnection allows for the generation to be sized at up to 95% of the minimum load of the customer's facility.

The minimal load calculation would be suitable for an area network. The calculation would also be suitable for spot networks provided that a small allowance was made to ensure that some load is drawn at all time through the network protectors.

New loads may not be suitable for this method as there is no historical data on which to base the generation sizing. Energy modeling may provide a substitute for measured data, but it is expected that there may be an inherent uncertainty to using forecasted data, and utilities may be justified in establishing a more conservative limit relative to the modeled minimum load.

The advantages of a minimum load approach are in its simplicity. By using a minimum load value (up to 95%), it can be ensured that the generation system is correctly sized to ensure that export from the customer's generation to the secondary network does not occur. There are no expensive relays to purchase and this solution will assist the value proposition for small generators where costly protection requirements can make the systems uneconomical.

There are also some disadvantages to this approach. If the particular building has a cyclic load, for example a low load at the weekends but high in the week. This causes the generation system to be sized for the weekend load and may be negligible compared to the weekday load. Also a building's load may change over time. For example a building may be retrofitted with energy efficient systems which reduces the minimum load of the site or the occupancy level changes and puts the generation at risk of exporting generation.

6.2.2 Minimum Import Relay

A minimum import relay can be used to inhibit generation when the import to a customer's site falls below a pre-defined level. The relay measures the incoming power to the customer meter and would typically be installed at the point of common coupling with the utility. Should the customer's load fall past a pre-set level (e.g. 100kW) then the minimum import relay would operate and cause the generation to cease.

The minimum import relay has the advantage that it is not possible to reduce the load on a network protector to zero and risk its operation.

A minimum import replay is a good solution for a spot network. In a spot network, there are no other customers supplied and therefore some load is required to flow to the customer to prevent the network protectors having no load flowing through them.

A key disadvantage of a minimum import relay is that the majority of relays have to be reset manually, if the relay operates when the building is unoccupied then the generation system may be offline for a significant timescale. If this is expected to happen regularly due to the occupancy level of the building then the building only should consider automating the reclosure of the relay after preset conditions are met. The relays can also be a costly solution for small generation systems where there is not a large capital cost to spread the cost of the additional protection over.

6.2.3. Reverse Power Relay

A reverse power relay is very similar to a minimum import relay except that it allows the incoming power to fall to zero before it operates. The relay measures the incoming power to the customer meter and would typically be installed at the point of common coupling with the utility. Should the customer's load fall to 0kW then the relay would operate and cause the generation to cease.

A reverse power replay is a good solution for an area network with low penetration levels of generation. In an area network several customers are connected to the same transformer. This means that if one customer with generation draws zero load, other customers would be expected to draw load , keeping power flowing through the network protectors and not causing them to operate.

If the area network has a high penetration level of generation a minimum import relay would be a better solution to ensure that load is always drawn through network transformers.

A reverse power relay is not a good solution for a spot network. A spot network requires some minimum load to flow via the network protectors to stop them from operating. A reverse power relay may cause the network protectors in a spot network to operate frequently. In a spot network, there are no other customers supplied and therefore some load is required to flow to the customer to prevent the network protectors having no load flowing through them.

A key disadvantage of a reverse power relays is that the majority of relays have to be reset manually, if the relay operates which the building is unoccupied then the generation system may be offline for a significant timescale. The relays can also be a costly solution for small generation systems where there is not a large capital cost to spread the cost of the additional protection over.

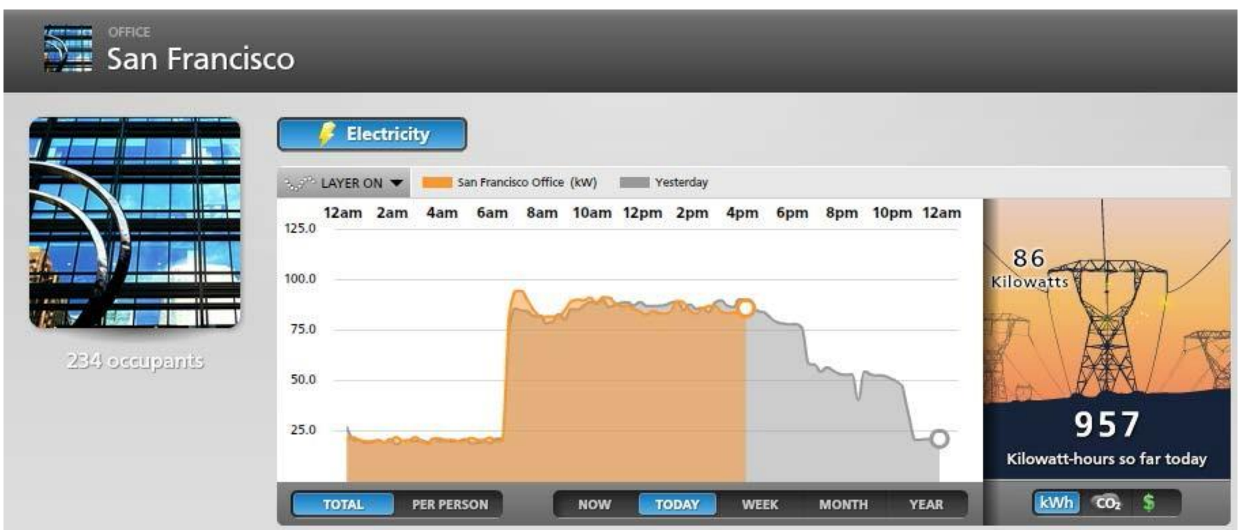
6.2.4 Dynamically Controller Inverters

A dynamically controlled inverter has the ability to lower the output of a generation source in response to a control signal. The inverters can be used to allow a PV system to reduce its power output as the load of a building reduces to prevent export of energy.

Within the minimum load methodology, typically a generation system such as photovoltaic are drastically undersized. A typical buildings load will be lowest in the evenings and/or at weekends. Daytime load is often significantly higher that nighttime load, which is when generation such as PV will produce its energy.

The figure below shows the energy profile for a single day (1/30/14) for the two floors of the Arup office in San Francisco.

Figure 9: Arup San Francisco Office Profile



If a PV system was sized using a minimum load calculation, the generation would only be sized at around 23 kW peak capacity. Sizing this for the actual daytime load of 75kW would ensure that the generation output roughly matches the load profile of the building. A calculation would be required to determine the optimum size of the PV based on the weekday / weekend load and the expected turn down events of the generator.

Installing a dynamically controlled inverter in this situation would also ensure that if the load dropped, so does the output of the generation, removing the export risk while maximizing the size of the generation to match the load.

As an additional level of security, a reverse power flow relay could be installed if deemed necessary.

Dynamically controlled inverters are now becoming commonly available in the market place.

The Smart Inverter Working Group (SIWG) is developing standards[8] for inverters that are expected to be compulsory under Rule 21 connections from October 2015.

The SIWG is proposing all inverters connected to the utility distribution system contain the following features.

- Support anti-islanding to trip off under extended anomalous conditions.
- Provide ride-through of low/high voltage excursions beyond normal limits.
- Provide ride-through of low/high frequency excursions beyond normal limits.
- Provide volt/var control through dynamic reactive power injection .
- Define default and emergency ramp rates as well as high and low limits.

Smart inverters are able to be controlled dynamically and change their power output in response to a signal. A meter would be installed on the incoming circuits to the building and as the incoming power draw from the utility falls, so would the output from the generation.

Adding electricity storage to a dynamically controlled inverter set would enable any excess energy to be stored and used on site.

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[8]http://www.energy.ca.gov/electricity_analysis/rule21/documents/recommendations_and_test_plan_documents/

CHAPTER 7: Conclusion

CIRE projects allow members of a community to have some or all of their electricity needs supplied from renewable sources. The objective of this report was to determine whether interconnection costs present barriers that may inhibit increased penetration of community renewable energy generation into the electricity network in California.

This report has identified the following technical and cost barriers to community renewable energy development:

1. generation installed that is greater than 15% of a line's peak load
2. generation that requires distribution upgrades /back-feeds a utility transformer
3. any generation connection to a utilities secondary or spot network

During the feasibility process of any generation project, other than residential roof mounted solar, we would recommend procuring a pre-application report. The pre-application report will provide all of the required information to be able to estimate the likely interconnection costs and determine if the project remains viable. The report can be procured early in the development process and avoid a developer sinking costs into a development that will ultimately not be economic. The pre-application report will also allow calculations to be undertaken to determine if the generator exceeds the line capacity break points and/or is expected to export power via a utility distribution transformer.

For secondary network connections, the challenges of connecting generation in these areas are due to the protection that these networks employ to remain safe. Power must flow through the network protectors to ensure they do not operate and isolate the circuits. Any generation that can reduce a customer's load towards zero risks operating the network protectors. Three potential solutions were investigated as part of this study:

1. Allow export toward 100% of minimum load for existing buildings with proof of minimum load for several years.
2. Install minimum import relay or a reverse power relay. This can ensure that generation is sized for a more typical building load profile and at the rare times of low load, controls can be installed on the customer side to curtail generation prior to the network protection operating.
3. Install dynamic controlled inverter system to follow the building's load to prevent export.

A utility will assess each interconnection request in a secondary network on a case by case basis. The solutions may allow generation to be connected to the secondary network in excess of the current standard sizing of 10% of minimum load. In addition to utility assessment the generation owner will make an economic assessment to ensure that with the required protection installed the project does not become uneconomical.

GLOSSARY

Term	Definition
CIRE	Community Integrated Renewable Energy
CPUC	California Public Utilities Commission
DG	distributed generation
eco-district	an urban planning tool that integrates objectives of sustainable development and reduces the ecological footprint of an area
IOU	investor-owned utility
kV	kilovolt
kW	kilowatt
local renewable power	generation installed on the distribution network so that benefits are gained locally
MW	megawatt
NEM	net energy metering
network protector	device used to prevent power from back-feeding from one transformer through another
OH	Overhead
PG&E	Pacific Gas and Electric Company
PURPA	Public Utility Regulatory Policy Act
PV	photovoltaics
UG	Underground
WDT	wholesale distribution tariff

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APPENDIX D:
Task 5- District Thermal Heating Concepts

Energy Research and Development Division
FINAL PROJECT REPORT

COMMUNITY INTEGRATED RENEWABLE ENERGY PROJECT

Task 5: District Thermal Energy Concepts

Prepared for: California Energy Commission
Prepared by: Arup, for the San Francisco Department of the Environment

ARUP

AUGUST 2014
CEC-500-2014-AUG

CHAPTER 1: Introduction

1.1 Project Description

The Community Integrated Renewable Energy (CIRE) Project will assess the feasibility of community energy, district heating and cooling, renewable electricity, storage and energy recovery, demand response, and microgrid distribution technology to serve members of a community with their energy needs.

The CIRE Project consists of the following tasks and subject areas:

- Task 1: Administrative and Reporting
- Task 2: Distributed Generation Connected to the Electricity Network
- Task 3: Community Generation and Enabling Technologies
- Task 4: Energy Storage and Generation Analysis
- Task 5: District Thermal Energy Concept

This report provides our preliminary findings for Task 5: District Thermal Energy Concept.

The goal of this task is to conceptually explore the benefits of a shared community thermal energy system that can support a phased development of new urban mixed-use buildings within the Central South of Market (SoMa) district in San Francisco.

The district analyzed in this report entails a single city block with six buildings representing a mix of the following land-uses:

- residential
- commercial/office
- retail

A conceptual district thermal scheme and a conceptual distributed thermal energy scheme were developed for this district. This allowed for the development of the following analyses for both schemes:

- energy, resource, and carbon emission simulations
- capital cost estimation
- operations and maintenance cost estimation
- life cycle or “net present cost” estimation

This set of analysis was used in this task to demonstrate the business case for a district thermal scheme in an urban setting. In parallel, this report explores social and CIRE benefits of district thermal energy schemes, including the following:

- ability to unlock public and community spaces
- ability to integrate CIRE
- ability to leverage locally available resources

1.2 EPA Smart Growth Report Progress and Synergy

In 2012, the City and County of San Francisco (the City) applied to the United States Environmental Protection Agency's (EPA) Smart Growth Implementation Assistance (SGIA) program for support in encouraging district-scale energy systems in two development districts, the Central SoMa and the Transit Center, of downtown San Francisco

The application was successful, and the final report titled *District-Scale Energy Planning* (an EPA smart growth report) was completed in April 2014. The report documented a roadmap for districts and cities to assess the viability of district-scale energy systems. The report provided various tools such as parcel evaluation and technology filters, and outlined the following four-phase implementation process:

- pre-feasibility
- feasibility
- project development
- operation, optimization, and expansion

The pre-feasibility and feasibility steps outlined in the final smart growth report are used as the guiding principles for this CIRE task.

1.3 System Selection Criteria

As described in *District-Scale Energy Planning*, a multi-criteria assessment is used to identify the optimal community thermal system for the indicative community. A multi-criteria assessment is the first step in a district thermal feasibility study. It utilizes the data and information gathered in the pre-feasibility study (see CHAPTER 3) to qualify and compare the economic, environmental, and spatial benefits of various alternative community district thermal systems, as illustrated by Figure 1.

Figure 1: Community Thermal System Selection Criteria

Community Thermal System	GHG REDUCTION POTENTIAL	WATER REDUCTION POTENTIAL	TOTAL ENERGY	TOTAL ENERGY COST	CAPEX	OPERATIONS & MAINTENANCE	PARCEL PLANT SIZE	CUP SIZE	PERMIT/APPROVAL RISK	DISTRIBUTION COMPLEXITY	RESILIENCE	COMMERCIAL RISK	WEIGHTED SCORE
BAU | DISTRIBUTED HEATING & COOLING													
OPTION 1 | CENTRAL HEATING & COOLING													
OPTION 2 | CENTRAL COOLING, DISTRIBUTED HEATING													
OPTION 3 | WSHP + CONDENSER WATER NETWORK													
OPTION 4 | COGEN + CENTRAL HEATING AND COOLING													
OPTION 5a | TRIGEN (Heating prioritized) + CENTRAL HEATING AND COOLING													
OPTION 5b | TRIGEN (Cooling prioritized) + CENTRAL HEATING AND COOLING													
OPTION 8 | CENTRAL HEATING AND ENERGY RECOVERY CHILLERS													
WEIGHTING	5.0	4.0	4.0	3.0	3.0	3.0	1.0	2.0	2.0	3.0	4.0	2.0	

Legend
1 Least favorable, Least important
5 Most favorable, Most important
Quantitative indicators
Qualitative indicators

The weighting of the thermal system selection criteria are discussed in Section 4.1 and are applied to the CIRE task 5 report in order to reflect the unique goals of the city of San Francisco and those of the Central SoMa district.

The task 5 study also utilizes the parcel hosting, parcel connecting, and base thermal load tools developed in the EPA smart growth report in order to determine the appropriate configuration of the indicative district thermal energy scheme for the Central SoMa district.

1.4 Low-Temperature District Heating

Low-temperature systems refer to district heating systems that operate at supply temperatures of approximately 130°F (as compared to 180°F to 250°F+). Low-temperature systems are also commonly known as 4th generation district heating systems per the categorization summarized in Table 1.

Table 1: District Heating Classification[3]

1st	Steam	–
2nd	High-temperature water	250°F
3rd	Medium-temperature water	190°F
4th	Low-temperature water	130°F

This study emphasizes low-temperature heating systems, which have proved to be a high-performance solution for cleaner and more efficient district thermal energy schemes.

Advantages of low-temperature systems are as follows:

- lower distribution losses (less differential temperature between fluid and ground)
- higher generation efficiencies through use of condensing boilers
- easier utilization of CIRE and non-CIRE renewable resources and locally available waste heat due to better temperature matching with solar availability and waste heat temperatures
- ability to heat pump, which future-proofs district thermal systems to be run more readily by cleaner future power grids in lieu of combustion heating with fossil fuels
- simplification and reduced costs for system maintenance due to lower thermal stress and system pressure
- larger variety of suitable piping and insulation material available due to lower temperatures and corresponding thermal stresses and/or losses

Together, these energy efficiency impacts make low-temperature thermal systems the choice for communities targeting low carbon and/or zero net energy (ZNE) goals.

The drawback for low-temperature district heating is the resulting requirement for greater flow rates (gallons per minute), and therefore larger pipes and more pumping energy. However, costs associated with this can be mitigated by the resulting reduction in source fuel combustion, operations and maintenance (O&M) costs and, in some jurisdictions, carbon taxes.

Another advantage with low-temperature systems is that technologies like heat pumps, solar thermal collection, and recovery of local waste heat from new sources such as electrical substations, data centers, office heat rejection, and sewer mains, become technically and

[3] Wiltshire, Robin. *Low Temperature District Heating*. Building Research Establishment, 2012

economically feasible. Integration of such technologies can decrease the environmental impact from district heating energy significantly by directly avoiding combustion of fossil fuels.

Denmark has long been the world leader in district heating, historically with deep cogeneration (electrical and thermal heating) penetration. However, there are now a number of Danish examples of low-temperature systems with wind-powered ground-source heat pumps. Additional Danish schemes plan to retire cogeneration facilities to make way for similar electrically powered heat pump schemes.

According to *Heat Plan Denmark*, a scientific study performed by Ramboll and Aarhus University, it is possible for the heating sector in Denmark to become near carbon neutral by 2030 Low-temperature systems coupled with heat pumps and powered by a national power grid that has a deep wind power penetration is one of the main strategies in achieving this goal. Although the renewable energy penetration is not yet as deep in California as it is in Denmark, the opportunity exists over time in many areas of California to readily source heating energy through heat pump technology (ground coupled or energy recovery based).

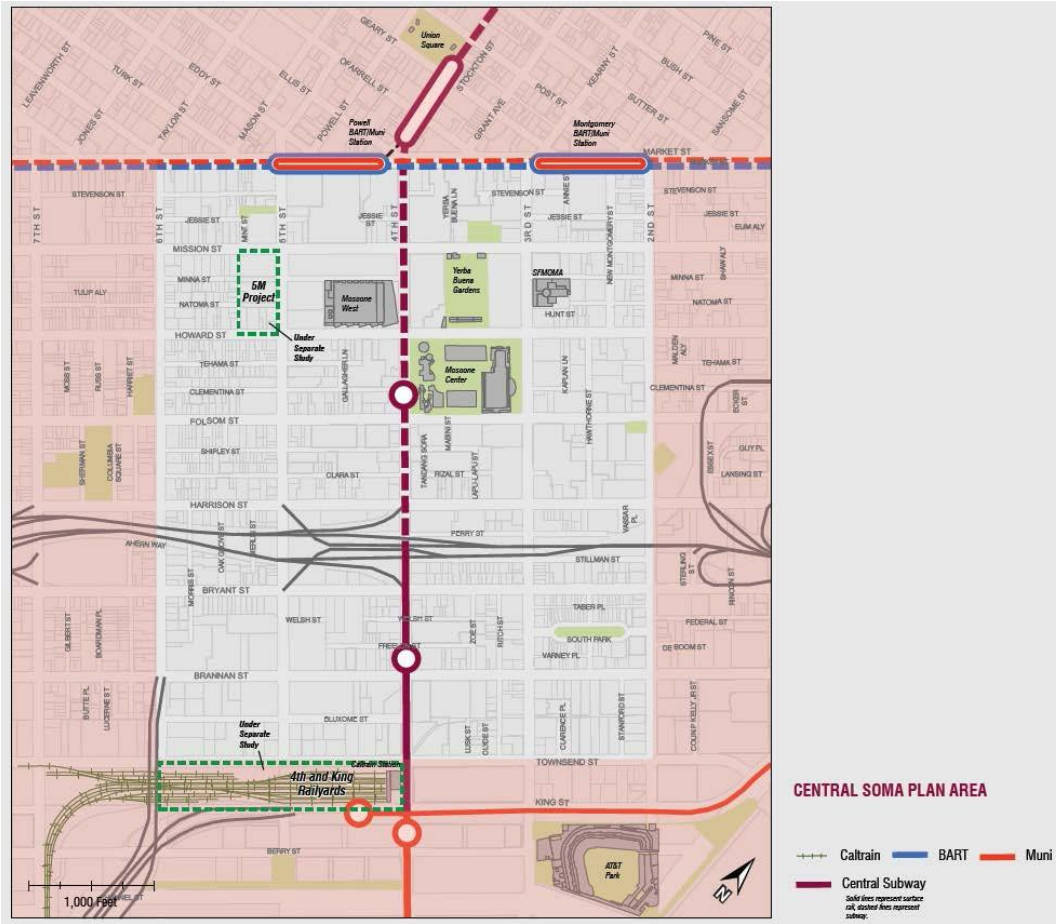
CHAPTER 2: Study Site Selection

2.1 Central SoMa Introduction

In San Francisco, 56% of greenhouse gas emissions are associated with lighting, heating, and cooling buildings. The City and County of San Francisco (CCSF) is committed to developing and implementing aggressive and diversified approaches to reducing these emissions while continuing to absorb anticipated regional population growth. One such approach is to plan carbon-free community-scale energy resources locally with potential to scale regionally and statewide. A further replicable commitment is to increase jobs and housing in transit-oriented and pedestrian-oriented neighborhoods — San Francisco has the lowest per capita emissions rates in the Bay Area, and greater population and job growth will further reduce per capita emissions.

Central SoMa (South of Market) is a dense, transit-rich area of San Francisco that extends from Second Street to Sixth Street and from Market Street to Townsend Street. The area has been identified as a priority development area by the City Planning Department and is the subject of a significant rezoning effort that encourages sustainable growth and creates substantial opportunities to align energy, transportation, water, and waste infrastructure systems. In addition to identifying the renewable energy resources and enabling technologies that could be appropriate for this district, the CIRE Project will identify ways CCSF can advance community-scale energy in this neighborhood and in communities like it throughout the state. These efforts include providing a strategy to coordinate multiple public and private interests, including identification of all key institutional stakeholders and relevant regulatory frameworks.

Figure 2: San Francisco Central SoMa Plan Area



Source: CCSF Planning Department

With the addition of the Central Subway along and under Fourth Street (under construction and scheduled to begin operation in 2018), undeveloped or underdeveloped parcels in the transit corridor offer a major development opportunity. CCSF anticipates approximately 12,000 new housing units and 35,000 jobs in this area. The Central SoMa Plan, released in draft in April 2013, proposes rezoning this area for dense, transit-oriented, mixed-use growth and provides opportunities to incorporate district-level energy infrastructure.

In addition to providing local energy, creating CIRE projects will greatly enhance the resiliency of Central SoMa. The ability to generate power and provide local energy is essential for both the immediate and long-term recovery from a large earthquake or similar disaster.

The Central SoMa CIRE Project has the potential to inform similar planning efforts in other parts of the state, particularly those with new development areas, major infrastructure projects, or significant revitalization planned.

2.2 Central SoMa Flower Market Area

Central SoMa contains a diverse mix of buildings. This report considers a fictitious newly built mixed-use development in the SoMa Flower Market area that is expected to be typical of the Central SoMa district.

Figure 3: Existing Flower Market Area in Central SoMa

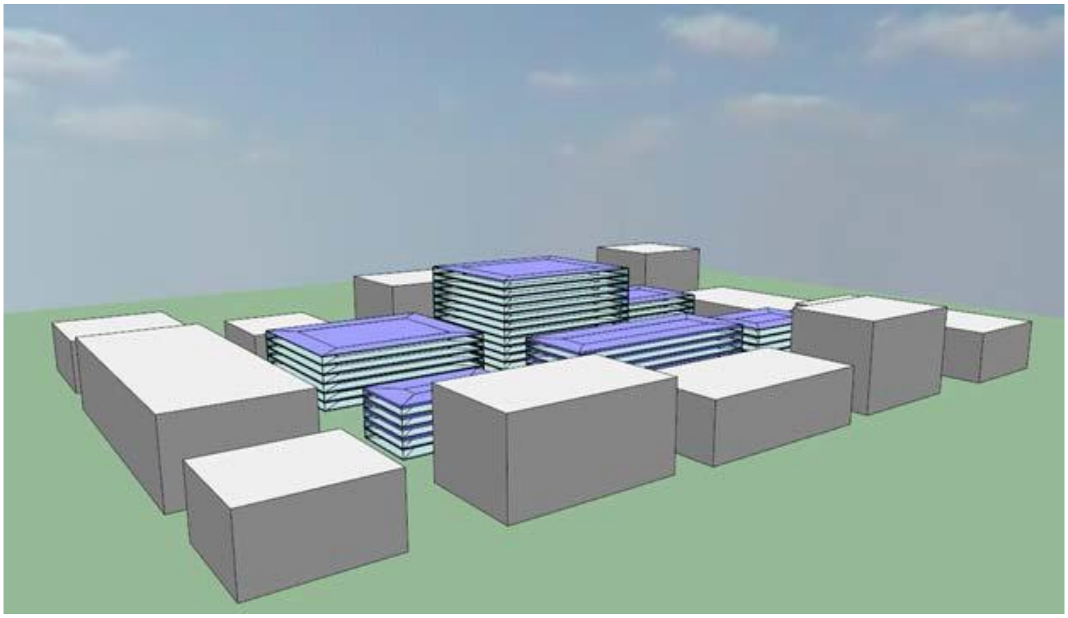
2.2.1 Planned Development

The indicative community development assumes the following:

- total property floor area of 1,981,000ft^2
- 67% commercial, 20% residential, and 13% retail area split (all retail on ground floor)
- floor-to-floor height of 14ft in all buildings
- varying building heights between 65ft and 130ft
- neighboring existing buildings (included in model only for shading purposes)

Figure 4 illustrates an indicative model of a community development at the Flower Market site. The purple buildings represent the community studied, while the gray buildings represent neighboring blocks.

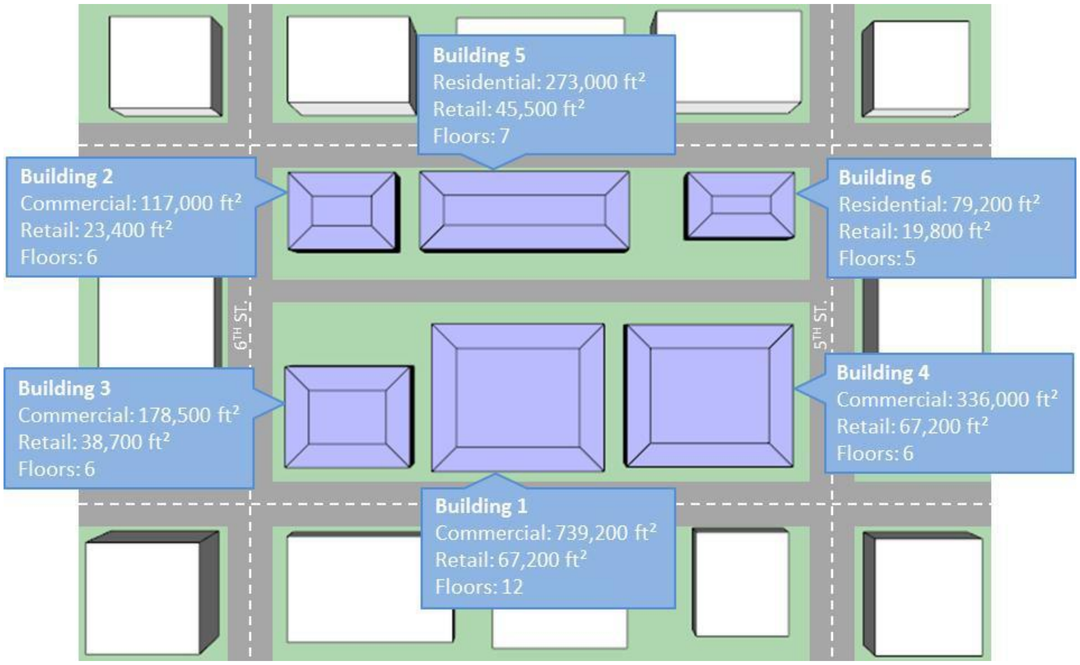
Figure 4: Indicative Model of a Community Development at the Central SoMa Flower Market Site



The community buildings are all assumed to be new-construction, high-performance buildings, meeting or exceeding California Title 24 requirements. They are also assumed to include forced air overhead variable air volume systems and building level chilled water and heating water plants which are the most prevalent among developer led buildings.

Figure 5 provides a map of the assumed massing for each of the six buildings in the indicative community and illustrates the mix of main public streets, secondary public streets, and service alleys that bound the development.

Figure 5: Assumed Building Massing



2.2.2 Building Phasing

The construction phasing, and subsequently the "in service date" (ISD), of buildings served by a district thermal energy system are critical planning parameters. This is because the thermal loads at intermediate build-out points are equally as important as the loads realized at full build-out, and primary HVAC systems need to be phased-in so that efficient operation of the system is ensured at all times.

For the purposes of this study, the indicative phasing plan summarized in Table 2 has been assumed to demonstrate the exercise of planned system phasing. This exercise can be replicated by other districts and cities looking to explore district thermal systems.

Table 2: Assumed Building Phasing for Indicative Community

Building	Phase	ISD	Area (ft^2)	Cumulative Area (ft²)
Building 1	1	2018	806,400	1,265,300
Building 2		2018	140,400	
Building 5		2018	318,500	
Building 3	2	2022	241,200	716,400
Building 4		2022	403,200	
Building 6		2022	99,000	

CHAPTER 3:
Pre-Feasibility

The approach established in the study titled "District-Scale Energy Planning" was followed to conduct a pre-feasibility study for a district thermal system serving the indicative development at the Flower Market area. This section documents the process and findings from this study, which are as follows:

- The definition and goals for the district are extracted and documented in Section 3.1.
- The potential barriers to a district thermal system in the Flower Market area are identified in Section 3.2.
- The future system potential is explored in Section 3.3.

3.1 District Definition and Goals

The Flower Market's location at the southwest edge of SoMa situates it within the neighborhoods being planned for up-zoning as part of a major central subway transportation project. A pre-feasibility study for the Central SoMa district has already been completed as part of the EPA smart growth report and is therefore a good resource for assessing the viability of a community thermal system serving the Flower Market area development.

The pre-feasibility study defined the district as follows:

- a potential eco-district zone due to significant up-zoning
- an area slated for public realm, transportation, and building improvements
- a large neighborhood with diverse uses that is increasingly becoming a home to the city and region's high tech industry

The district goals for Central SoMa were also documented in the pre-feasibility study:

- establish a net zero carbon/net zero energy district
- prioritize energy efficiency in existing and new developments
- encourage community-scale clean energy systems in areas with intensive infill capacity and anticipated growth
- develop incentives to encourage the implementation of community-scale clean energy projects
- explore the potential of renewable energy generation and procurement

A community thermal energy system is well aligned with both the characteristics and the goals of the SoMa district.

3.2 Potential Barriers

The potential barriers identified in the pre-feasibility study were as follows:

- the Central Subway tunnel which will run through the district, making connections from either side challenging
- the complex ownership pattern in the district with multiple property owners and parcels at various stages of development

Since the Flower Market is on the west side of the proposed Central Subway tunnel, the first potential barrier is not an immediate concern for this study.

The second potential barrier is typical of an urban fabric. Property owners will have to be engaged early and often in order to mitigate their potential lack of interest or commitment to a community energy system. This will most likely require that the ultimate community energy system operator and the building owners be invited for engagement by a mutual third party or "convener." A community energy system can help meet the San Francisco energy reduction goals while also reducing building owner's capital cost, maintenance, and operational costs. Entities suited to play the role of convener are as follows:

- City Planning Department
- City Department of the Environment
- Building Owners and Managers Association (BOMA)
- International Facilities Management Association (IFMA)
- San Francisco Planning & Urban Research (SPUR)
- business improvement district(s)

Cities and districts exploring district thermal energy should identify and engage trusted institutions to effectively manage diverse ownership interests.

3.3 Future System Potential

As described in the EPA smart growth report, the final step in the pre-feasibility stage is to establish the existing and future loads of the development which are to be satisfied by the community thermal system. These loads include both peak thermal demands, and thermal load distribution.

3.3.1 Peak Demands

As described in Section 2.2, this study entails new indicative development at the Flower Market only. The peak thermal demands are therefore estimated using best practice assumptions that align with new high-performance, developer led buildings in the mild San Francisco climate. These assumptions are summarized in Table 3.

Table 3: Peak Thermal Load Assumptions

Commercial	400ft^2/ton	15 btu/h/ft^2
Residential	700ft^2/ton	10 btu/h/ft^2
Retail	350ft^2/ton	20 btu/h/ft^2

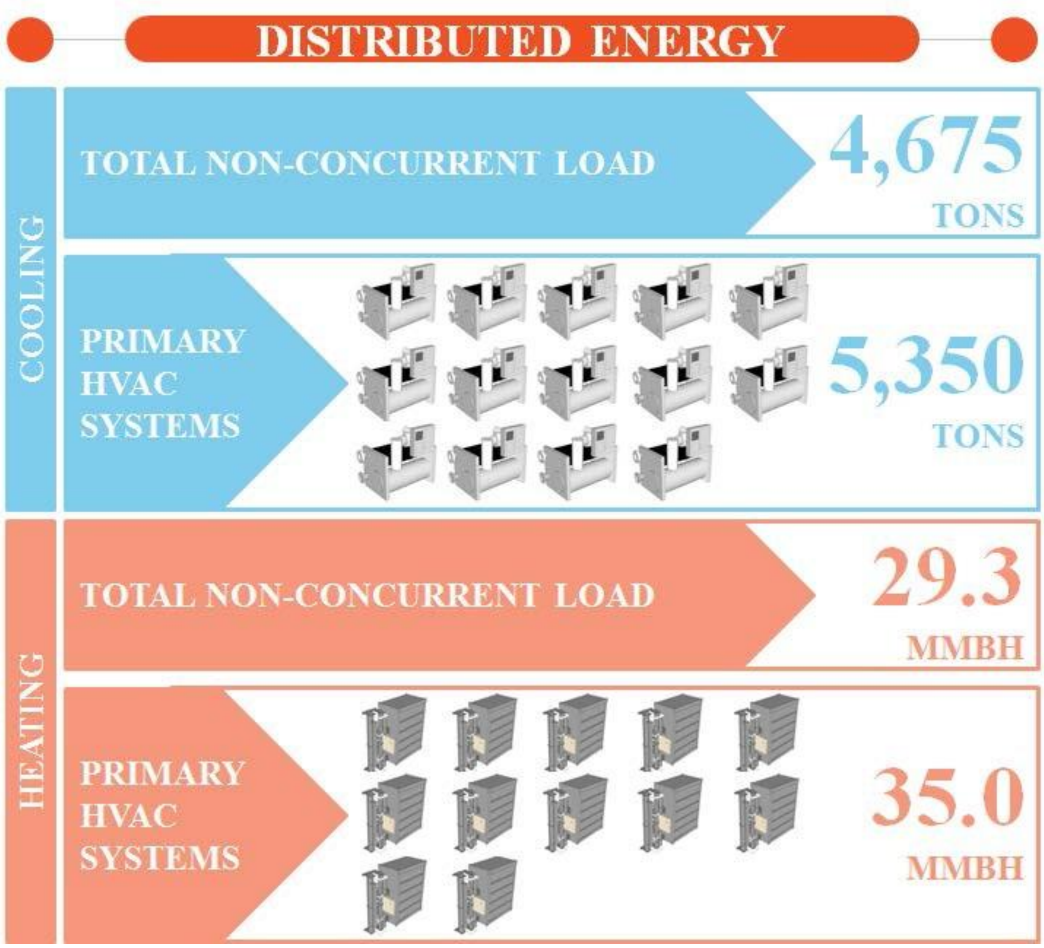
Without a community district thermal system, each building would include its own heating and cooling system. These systems would be sized to meet the peak demands of each building individually without consideration for concurrent demands of adjacent buildings. Under this scenario, the peak demands and subsequent likely primary system sizes for the indicative district are summarized in Table 4.

[4] Includes space heating and domestic water heating

Table 4: Peak Thermal Loads and Primary Systems: Distributed Approach

Building	Peak Space Cooling Demand	Likely Space Cooling Primary System		Peak Space and Domestic Water Heating	Likely Space and Domestic Water Heating Primary System Capacity		Notes
	Tons	Quantity of Chillers	Total Capacity (tons)	MMBH	Quantity of Boilers	MMBH	
1	2,040	3	2,400	12.4	3	15.0	1, 3
2	360	3	450	2.2	2	3.0	1, 3
3	550	2	600	3.4	2	4.0	2, 3
4	1,035	2	1,100	6.4	2	7.0	2, 3
5	520	2	600	3.6	2	4.5	2, 3
6	170	2	200	1.2	1	1.5	2, 3
Total	4,675	14	5,350	29.3	12	35	
Notes							
1.	Assuming building requires a 3 x 40% duty capacity chiller design						
2.	Assuming building required 2 x 50% duty capacity chiller design						
3.	Assuming the following standard condensing boiler sizes:						
				Output	Input		
				4.65	5	MMBH	
				2.3	2.5	MMBH	
				1.84	2	MMBH	
				1.38	1.5	MMBH	

Figure 6: Primary Systems: Distributed Approach



In contrast to a traditional distributed building approach (i.e., each building is served by its own system), a community district thermal system captures the diversity of energy use that exists across the site and is therefore sized to meet the simultaneous (i.e., concurrent) peak load of all the buildings collectively. The energy model combining the Flower Market area buildings suggests that this diversity is approximately 7% for cooling and 12% for heating, meaning that the corresponding systems can be decreased in installed capacity by this amount. More importantly, and as shown in Figure 8, the systems can be combined into a central location and significantly reduced in number since a few pieces of larger equipment can replace multiple smaller units.

The peak concurrent loads resulting from connected building diversity and the subsequent ultimate[5] primary cooling and heating system sizes under a district thermal energy system are summarized in Table 5.

[5] Primary Cooling & Heating systems in a district thermal energy plant will typically be phased in to match the incremental demands of buildings as they are built.

Table 5: Peak Thermal Loads and Primary Cooling and Heating Systems: District Approach

District Thermal System	Peak Space Cooling Demand	Likely Space Cooling Primary System		Peak Space and Domestic Water Heating	Likely Space and Domestic Water Heating Primary System Capacity		Notes
	Tons	Quantity of Chillers	Total Capacity (tons)	MMBH	Quantity of Boilers	MMBH	
	4,345	6	4,900	25.8	7	30.0	1, 2, 3, 4
Notes							
1.	Assuming 4 x 1,000 TR chillers and 2 x 450 TR chillers						
2.	Assuming 5 x 5/4.65 MMBH input/output boilers, and 2 x 2.5/2.3 MMBH input/output boilers						
3	Assuming district cooling plant requires 60-80% redundancy with one chiller down						
4	Assuming district heating plant requires 60-80% redundancy with one boiler down						

Figure 7: Primary Cooling and Heating Systems: District Approach

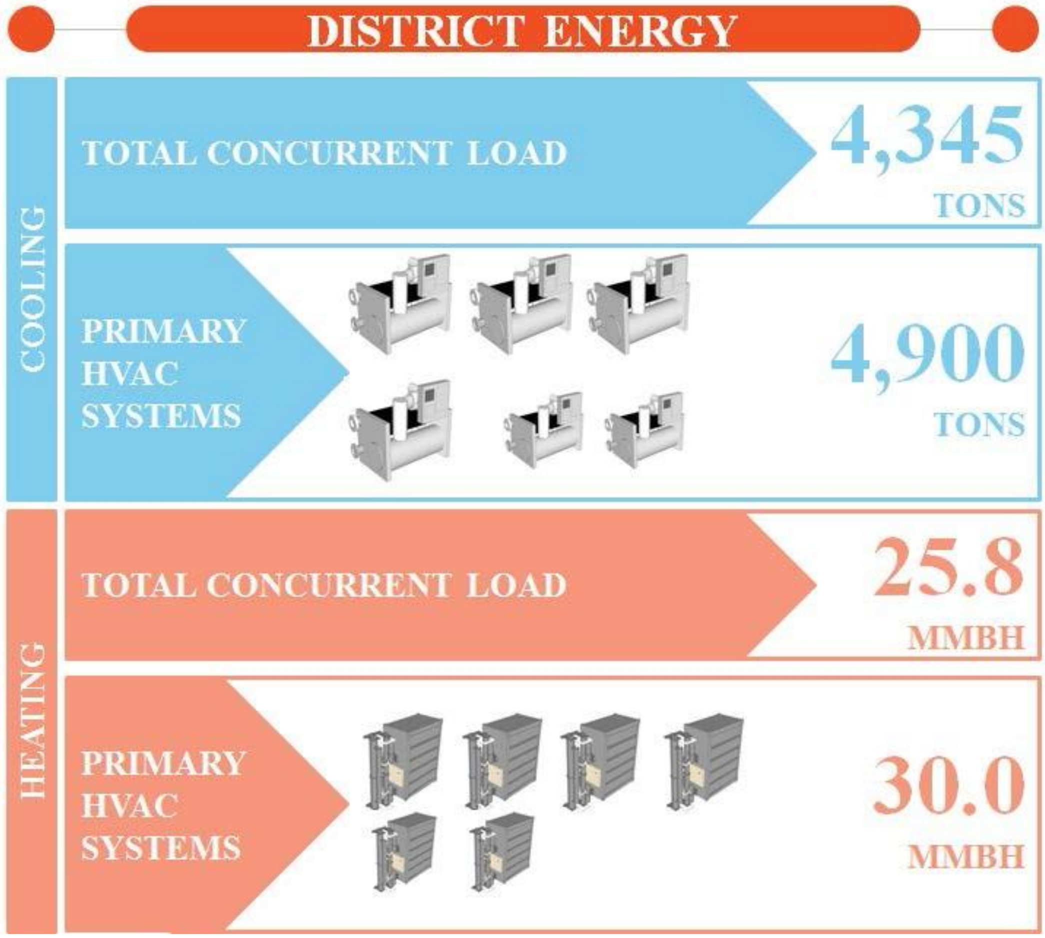
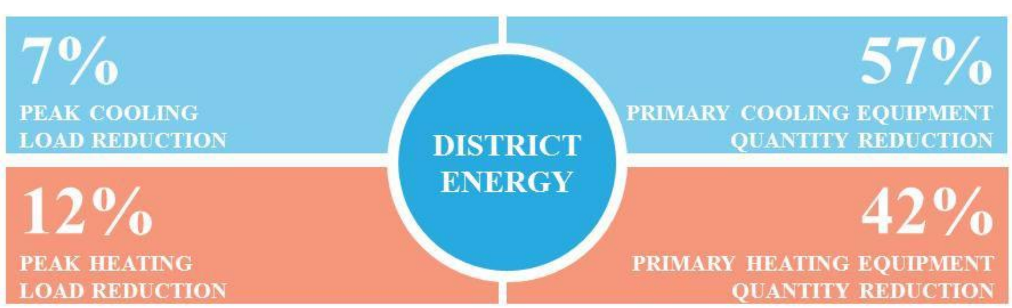


Table 4 and clearly indicate the dual benefits of peak demand diversity capture, equipment quantity, and equipment redundancy minimization that are possible when primary heating and cooling systems are shared across buildings in a community. These benefits are summarized in Figure 8.

Figure 8: District Energy Benefits for Indicative Flower Market Community



Further benefits related to spatial savings associated with the community approach are discussed in Section 10.4.

Costs related to the community approach (e.g., connective piping) are discussed in Section 9.1.

3.3.2 Load Distribution

The thermal loads of the Flower Market buildings were modeled in the Integrated Environmental Solutions (IES) Virtual Environment (VE) software package.[6] Assumptions associated with the IES VE load model can be found in APPENDIX A1.

A similar modeling approach can be replicated by other cities and districts looking to explore district thermal systems in advance of new development. Cities and districts exploring district thermal systems serving existing communities should try to attain the actual hourly thermal loads of each building to the extent possible.

The heating load distribution results for the Flower Market buildings are illustrated in Figure 9 and Figure 10. Figure 9 illustrates the steady year-round heating baseload for domestic end uses such as showering, cooking, and cleaning (i.e., domestic water heating, DHW) needs of the community. The total heating values shown in Figure 9 also illustrate that the comfort heating (i.e., space heating) peaks are much larger than the domestic water heating baseload in magnitude and show seasonal variations.

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[6] Integrated Environmental Solutions (IES). http://www.iesve.com/software

Figure 9: Annual Distribution of Heating Load

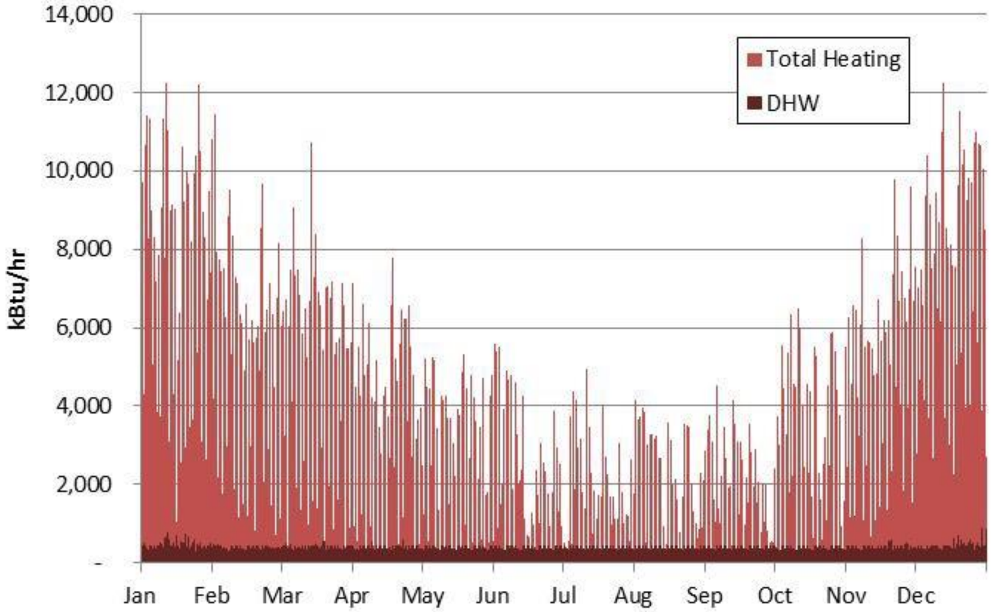


Figure 10 is a histogram of the community's heating loads and is useful in illustrating the magnitude of the overall community base heat load. As Figure 10 suggests, there is an insignificant heating load that is truly 24/7 in nature. This is an important metric for assessing district thermal energy strategies that generate and utilize waste heat such as cogeneration, which depend on a significant base heat load for economic viability.

Figure 10: Heating Load Duration Curve

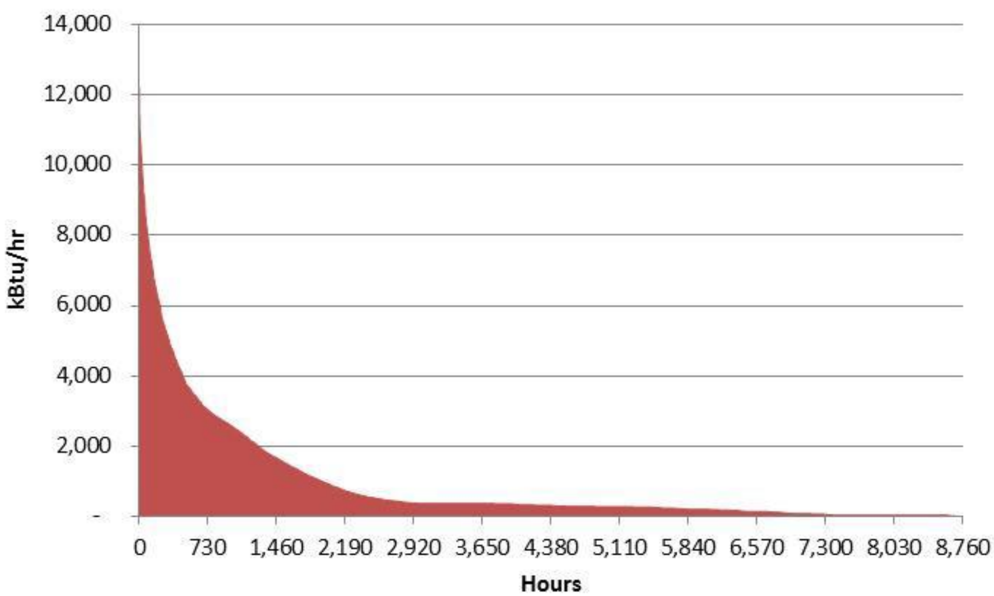


Figure 11 illustrates the cooling load distribution results of the simulation. It is apparent that though some cooling load is apparent in all months, it is not a steady year-round load such as the domestic water heating load seen in Figure 9. The seasonal peaks in load are as expected, with July through October being the dominant cooling season.

Figure 11: Annual Cooling Distribution

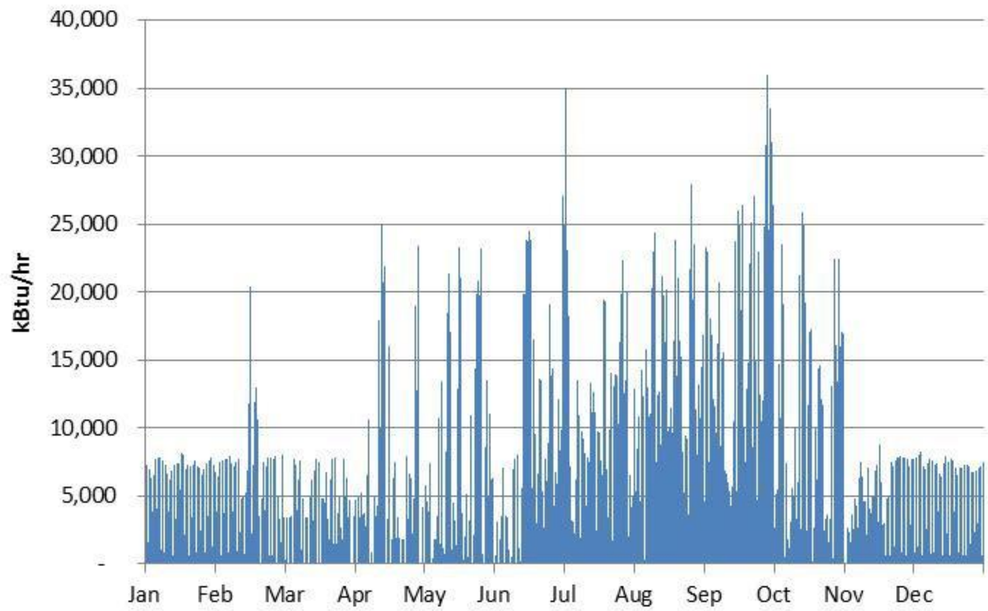
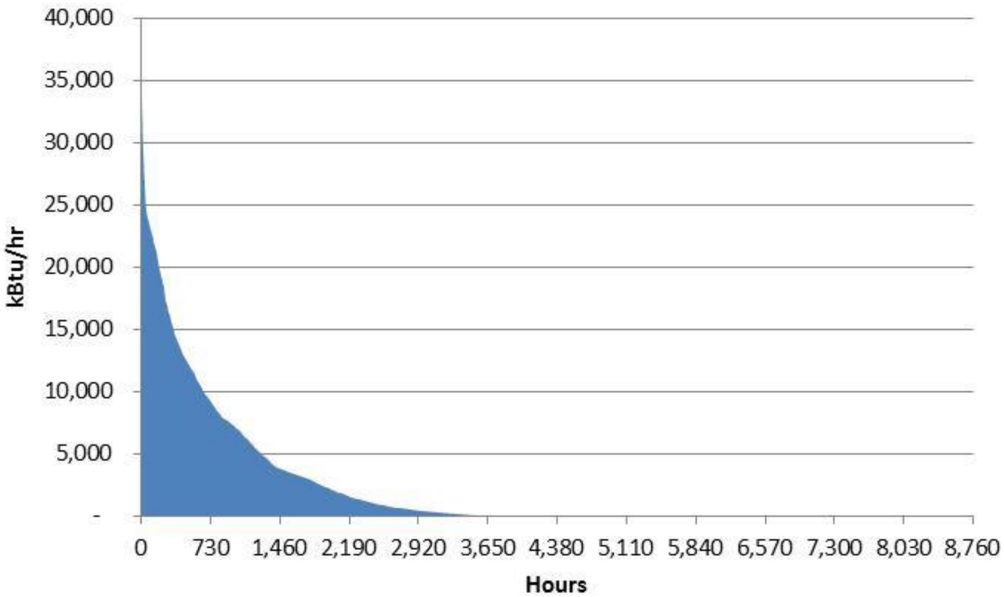


Figure 12 is a histogram of the community's cooling loads and is useful in illustrating the magnitude of the overall community base cooling load. Figure 12 not only suggests that there is no cooling load that is truly 24/7 in nature, but also that there is no cooling load at all for over 5,000 hours annually. This is an important metric for assessing district thermal energy strategies that generate cooling through tri-generation (cooling from waste heat absorption cycles, heating from waste heat, and electrical power).

Figure 12: Cooling Load Duration Curve



The thermal heating and cooling loads generated using the IES VE software simulation form the inputs to the Arup developed District Energy Feasibility (DEF) application for analyzing the performance of various district thermal energy systems. The resulting DEF model outputs energy and water consumption, and greenhouse gas emissions, which are used for system selection during the technology filtering exercise described in Section 4.1. Assumptions used in the DEF model can be found in Appendix A2.

The energy and water consumption, demands and costs from the DEF model are also used to establish operating costs for the selected indicative system as documented in Section 9.2.

3.4 Pre-Feasibility Conclusion

The indicative community at the Flower Market area is highly suited for district thermal energy. The City goals for Central SoMa align well with district thermal energy, the benefits of which can spur the growth planned for the area. Potential barriers have been identified and can be mitigated through early action and stakeholder engagement.

CHAPTER 4: Feasibility

The approach established in the study titled “District-Scale Energy Planning” was followed to conduct a feasibility study for a district thermal system serving the indicative development at the Flower Market area. This section documents the process and findings from this study which are as follows:

- Various district thermal technologies were identified and filtered as described in Section 4.1.
- Each parcel of the Flower Market site was studied to establish whether it was suited for hosting or connecting to the district thermal system as described in Section 4.2.
- A preliminary investigation of applicable codes, regulations and standards is documented in CHAPTER 5.
- A preliminary investigation of applicable permits is documented in CHAPTER 6.

4.1 Technology Filtering

The technology selection criteria developed in the EPA smart growth report and introduced in Section 1.3 was used to identify the optimal district thermal energy technology. A mix of 12 qualitative and quantitative criteria was used to aid in the filtering process as summarized in Table 6. These criteria address typical district energy considerations, but also several drivers that are specific to the city of San Francisco and the Central SoMa district.

The weighting applied to each criterion as appropriate for the City of San Francisco and the Central SoMa district is also tabulated. Cities and districts exploring district thermal energy should weigh filtering criteria based on project-specific goals.

The weighting uses a 5 for criteria with the highest strategic importance, and a 1 for criteria that are useful to track, but not directly aligned with strategic goals.

Table 6: Technology Filtering Criteria (QA=Quantitative, QL=Qualitative, W=Weight)

Criteria	Type	Description	W	Weighting Basis
GHG reduction potential	QA	The energy consumed to generate and distribute thermal energy to buildings results in GHG emissions locally and regionally. This is increasingly becoming an important metric that cities and districts use to assess the performance of technical schemes.	5	Reducing GHG emissions aligns with the ZNE goals of the City of San Francisco and the State of California, and is one of the key motivators for exploring CIRE. The highest possible weighting is applied.

Criteria	Type	Description	W	Weighting Basis
		The IES VE and DEF modeling exercise provides preliminary quantitative data that allow a comparison of these GHG emissions for distributed thermal energy systems against various district thermal energy systems		
Water reduction potential	QA	Building thermal energy systems utilize large amounts of process water. Various strategies at the multi-building or district scale can be employed to drastically reduce the amount of water consumed. The IES VE and DEF modeling exercises provide preliminary quantitative data that allow a comparison of process water consumption for distributed thermal energy systems against various district thermal energy systems	4	Water is a precious resource in California where 2013-14 marked the driest year on record. It is therefore weighted relatively highly for this study. Cities and districts assessing district thermal energy systems should weight water reduction potential appropriately.
Total energy use	QA	Total energy consumption compares the amount of primary energy (electricity and natural gas for example) required to satisfy a given amount of thermal load for distributed and district thermal energy schemes.	4	This criterion aligns well with the City of San Francisco's goals for ZNE and is therefore weighed highly.
Total energy cost	QL	Applying energy rate schedules to the total energy use metric above results in the total cost associated with the consumed energy. This forms part of the operating expense/budget for the system, and can be quantitatively measured using the IES VE and DEF models.	3	Though the cost of energy is an important measure for the purposes of setting annual budgets and cash flows, it is perhaps not as strategic an indicator for system selection as GHG emissions and energy consumption. A moderate weight has therefore been applied.
Capital expenditure	QL	Minimizing first costs or CAPEX associated with the thermal	3	Limiting CAPEX is likely an important criterion for most

Criteria	Type	Description	W	Weighting Basis
(CAPEX)		energy scheme is an important criterion for most projects. Establishing a first cost estimate requires a fairly detailed definition of the scheme such as a concept design and/or equipment quantification and sizing. It is therefore used as a qualitative criterion at the filtering stage in this instance to identify the preferred technology which can then be conceptualized and for which a cost estimate can be built. Other projects may choose to use the filtering step to identify multiple preferred options and develop CAPEX estimates (and subsequent life cycle cost analysis) for each.		cities and districts considering district thermal energy. However, it will rarely be one of the strongest strategic drivers for projects with a 25+ year life, in cities and districts that are primarily pursuing long range energy and carbon reduction targets. A moderate weight was therefore used for this criterion.
O&M expenditure (OPEX)	QL	Similar to the CAPEX, the minimizing the OPEX associated with the thermal energy scheme can be an important criterion for projects with limited budgets. The resource (energy and water) components of OPEX can be estimated using the IES VE and DEF modeling exercise. However, estimating the O&M component of OPEX is a fairly difficult task with little benchmark and industry data available. This is due to the fact that building owners and managers tend not to document and track the specific expenses associated with operating and maintaining thermal energy systems. Rather they maintain and budget for crews of staff to	3	Limiting OPEX is likely an important criterion for most cities and districts considering district thermal energy. However, it will rarely be one of the strongest strategic drivers for projects with a 25+ year life, in cities and districts that are primarily pursuing long range energy and carbon reduction targets. A moderate weight was therefore used for this criterion.

Criteria	Type	Description	W	Weighting Basis
		tend to all technical aspects of buildings, without breaking out costs by subcategories. OPEX is therefore used as a qualitative criterion at the filtering stage in this instance to identify the preferred technology. Section 9.2.3 documents the process that is then used to estimate the O&M component of OPEX for the preferred technology. Other projects may choose to use the filtering step to identify multiple preferred options and develop OPEX (and subsequent life cycle cost analysis) for each.		
Parcel plant size	QL	The reduction in plant area required at each parcel as a result of connecting to a district thermal system is one of the many primary value propositions of district energy.	1	Since district thermal energy is not the norm in most north America cities, building owners and managers are generally accepting of distributed thermal energy system plant space requirements. Though this reduction in parcel plant is perhaps undervalued, it is not typically a key driver, and the lowest weight was therefore applied.
Central plant size	QL	Limiting the size of the CUP is usually a criterion that comes up during district energy planning. Different district thermal technologies serving a given community can result in significantly different CUP sizes.	2	Aesthetic treatment and strategic location of the CUP can mitigate most of the concerns about the overall CUP size. A relatively low weight was therefore used.
Permit/ approval risk	QL	Certain district scale thermal technologies can trigger the need for permits and approvals over and above what might be	2	Early identification of required permits and approvals can usually mitigate the risk associated

Criteria	Type	Description	W	Weighting Basis
		typically expected for a typical buildings project. Attaining these approvals can result in additional effort and expense, and can cause project delays if not properly planned for.		with cost and schedule over runs. A relatively low weight was therefore used.
Distribution complexity	QL	Arguably the most challenging element associated with implementing district thermal energy within an existing urban environment is the design, planning, coordination, and construction of the distribution. Different district thermal technologies utilize a wide variety of distribution systems in terms of pipe quantity and size, which can be a limiting factor especially in congested underground zones.	3	Early and careful planning and coordination can mitigate the risk of distribution triggered project fatal flaws. However, certain underground zones may simply be too congested to allow for a technically feasible and cost effective distribution solution. A moderate weight was therefore applied.
Resilience	QL	One of the key value propositions of a district energy system is its ability to resist and/or bounce back from events that result in utility interruption and/or damage. District energy systems that have an electric generation component provide this resilience benefit which is more difficult to achieve at the single building scale.	4	Being a coastal city in a seismically active region, San Francisco is exposed to several disruption and/or disaster risks. The ability for district systems to alleviate the resistance to those risks and/or resume service after the risk is therefore an important criterion that is weighted relatively high.
Commercial risk	QL	One of the primary concerns existing building owners and managers associate with connecting to a district energy system is the perceived risk of giving up control of utility assets. Similarly, developers of new buildings in multi-private-owner environments such as cities are generally concerned about the realization of the proposed district energy scheme and its	2	The commercial risks of district thermal systems are well known and can easily be mitigated with proper planning and stakeholder engagement. A relatively low score was therefore applied.

Criteria	Type	Description	W	Weighting Basis
		ability to provide utilities to their buildings the day they open.		

Upon establishing the weighting for each of the filtering criteria, each of the following low-temperature district thermal systems that are compatible with buildings containing overhead VAV-type HVAC systems was scored:

- central heating and cooling (district heating and district cooling)
- central cooling, distributed heating (district cooling only)
- a condenser water network with distributed water source heat pumps (WSHP) within buildings (also known as an “ambient temperature” district thermal system)
- cogeneration with district heating and cooling
- tri-generation with district heating and cooling
- central heating and cooling with energy recovery chillers (also known as separate heat and power or SHP)

The quantitative scores indicated in Table 6 were scored using the preliminary results from the DEF model for the year 2030 which is not only the mid-point of the 25-year analysis, but also a fairly well established performance year for target setting and feasibility studies.

The qualitative scores were generated using differential analysis whereby each technology was considered against each other technology. Qualitative attributes of each technology alone can be used in this way to generate differential scores for the purposes of filtering only.

The resulting technology filtering scores, weights, and weighted scores are illustrated in Figure 13.

Figure 13: Technology Filtering Results

Community Thermal System	GHG REDUCTION POTENTIAL	WATER REDUCTION POTENTIAL	TOTAL ENERGY	TOTAL ENERGY COST	CAPEX	OPERATIONS & MAINTENANCE	PARCEL PLANT SIZE	CUP SIZE	PERMIT/APPROVAL RISK	DISTRIBUTION COMPLEXITY	RESILIENCE	COMMERCIAL RISK	WEIGHTED SCORE
BAU | DISTRIBUTED HEATING & COOLING	1.0	1.0	1.0	3.0	5.0	1.0	1.0	5.0	5.0	5.0	2.0	5.0	94.0
OPTION 1 | CENTRAL HEATING & COOLING	3.0	5.0	2.0	5.0	3.0	4.0	3.0	2.0	2.0	2.0	2.0	3.0	110.0
OPTION 2 | CENTRAL COOLING, DISTRIBUTED HEATING	3.0	5.0	2.0	5.0	4.0	4.0	4.0	4.0	3.0	3.0	2.0	3.0	123.0
OPTION 3 | WSHP + CONDENSER WATER NETWORK	5.0	5.0	5.0	1.0	4.0	3.0	2.0	2.0	3.0	3.0	3.0	3.0	128.0
OPTION 4 | COGEN + CENTRAL HEATING AND COOLING	3.0	5.0	2.0	5.0	2.0	2.0	3.0	1.0	1.0	1.0	5.0	2.0	104.0
OPTION 5a | TRIGEN (Heating prioritized) + CENTRAL HEATING AND COOLING	3.0	5.0	2.0	5.0	2.0	2.0	3.0	1.0	1.0	1.0	5.0	2.0	104.0
OPTION 5b | TRIGEN (Cooling prioritized) + CENTRAL HEATING AND COOLING	3.0	5.0	2.0	5.0	2.0	2.0	3.0	1.0	1.0	1.0	5.0	3.0	106.0
OPTION 8 | CENTRAL HEATING AND ENERGY RECOVERY CHILLERS	**5.0**	**5.0**	**5.0**	**5.0**	**3.0**	**4.0**	**3.0**	**3.0**	**2.0**	**2.0**	**2.0**	**4.0**	**136.0**
WEIGHTING	5.0	4.0	4.0	3.0	3.0	3.0	1.0	2.0	2.0	3.0	4.0	2.0	

Legend
1 Least favorable, Least Important
5 Most favorable, Most important
Quantitative indicators
Qualitative indicators

The technology filtering exercise identifies central heating and cooling with heat recovery chillers as the most promising technology for the indicative development in the Central SoMa Flower Market. Details about this system can be found in CHAPTER 2.

4.2 Parcel Evaluation

The next step after identifying a suitable district thermal technology is to evaluate each parcel in the development to establish its role in the greater scheme. To do this, the parcel evaluation tools presented in the EPA smart growth report are applied to the indicative Flower Market community.

Table 7 represents the thermal baseload evaluation tool from the EPA smart growth report. Note that buildings 1 through 4 in the indicative community are assumed as primarily commercial office, and buildings 5 and 6 are assumed as primarily residential, and so the thermal baseload evaluation tool has limited influence in parcel evaluation in this instance.

Table 7: EPA Smart Growth Report Parcel Baseload Evaluation Tool

Building Type	Heating Load	Cooling Load	Total Baseload (for scoring)
Health Care	4	5	5
Public Assembly	2	5	5
Residential	5	1	4
Hospitality	5	1	4
Food Service	2	4	3
Office	1	4	3
Education	3	3	2
Retail	3	3	2
Food Sales	1	3	1

Given the indicative nature of the development, the following assumptions were made to allow meaningful application of the EPA smart growth report parcel evaluation tools:

- All parcels are privately owned.
- The parcels along Brannon Street are considered to be more sensitive than the ones along Bryant Street.
- The larger buildings are more willing to host the CUP given they form the anchor load within the community.

Table 8 represents the parcel connecting scoring criteria established in the smart growth report. By incorporating the thermal baseload scores from Table 7, these criteria test the 6 parcels in the Flower Market area to assess their suitability to connect to the district thermal system.

Table 8: Flower Market: Connection Scoring Criteria

Parcel	Future Gross Area (Bldg Sq.Ft.)	Centrality (w/in district & then to Utility Plant)	Willingness (ownership)	Baseload Score (based on land-use type)	Connection Score
1	5	5	1	3	29
2	2	2	1	3	17
3	2	2	1	3	17
4	3	2	1	3	18
5	3	5	1	4	29
6	1	2	1	4	18
Typical Priority/Weighting	*1*	*3*	*3*	*2*	

Scoring Legend

1 (minimum)	*<100,000*	*fringe*	*Private*	*1*
2	*100,000 to 250,000*			*2*
3	*250,000 to 500,000*	*middle*	*Public/Private*	*3*
4	*500,000 to 750,000*			*4*
5 (maximum)	*>750,000*	*center*	*Public*	*5*
units	*Sq.Ft.*			*(See Exhibit 6)*

Table 9 represents the parcel connecting scoring criteria established in the smart growth report. By incorporating the thermal baseload scores from Table 8, these criteria test the 6 parcels in the Flower Market area to assess their suitability to host the CUP.

Table 9: Flower Market: Hosting Scoring Criteria

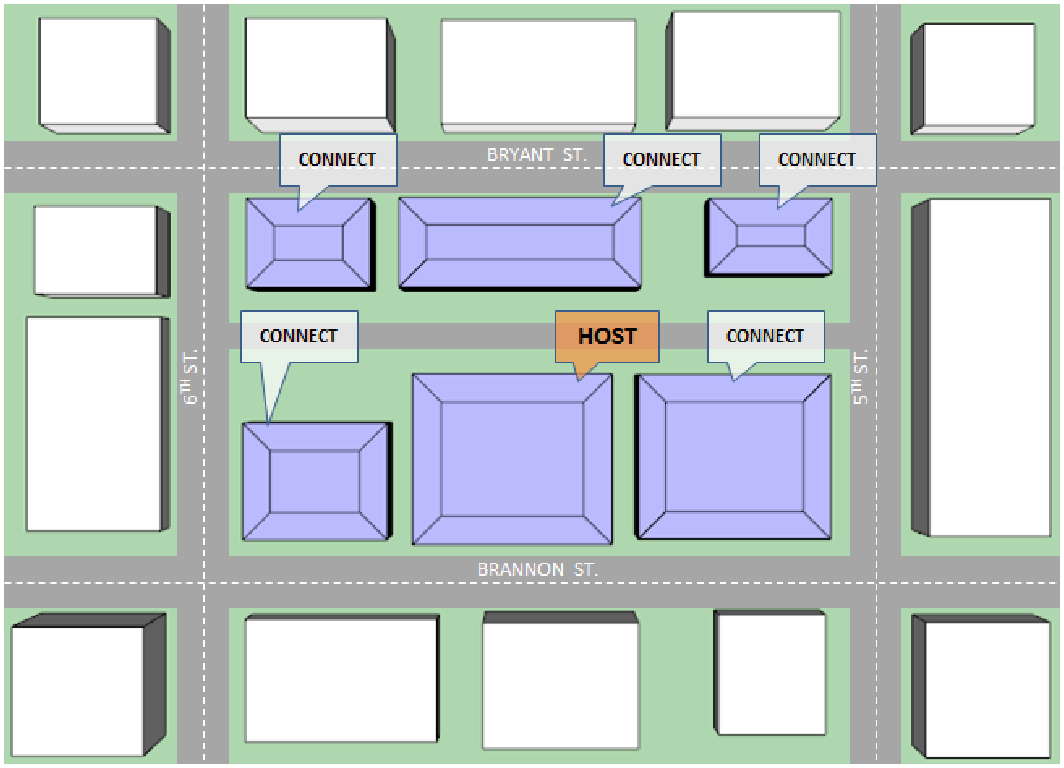
Building	Lot Area (Sq.Ft.)	Future Gross Area (Bldg Sq.Ft.)	Sensitive Location (subjective)	Centrality (w/in district & then to Utility Plant)	Willingness (ownership)	Connection Score (from Parcel Evaluation Table)	Utility Plant Score
1	4	5	4	5	1	1	54
2	2	2	4	2	1	4	42
3	2	2	4	2	1	4	42
4	4	3	2	2	1	4	41
5	3	3	2	5	1	1	41
6	2	1	2	2	1	4	33
Typical Priority/Weighting	*3*	*1*	*4*	*3*	*4*	*2*	

Scoring Legend

1 (minimum)	*<25,000*	*<100,000*	*"Very"*	*Fringe*	*Private*	*> 30*
2	*25,000 to 50,000*	*100,000 to 250,000*				*25 - 30*
3	*50,000 to 75,000*	*250,000 to 500,000*	*"Somewhat"*	*In-between*	*Public/Private*	*20 - 25*
4	*75,000 to 100,000*	*500,000 to 750,000*				*15 -20*
5 (maximum)	*>100,000*	*>750,000*	*"Not at All"*	*Center*	*Public*	*< 15*
units	*Sq.Ft.*	*Sq.Ft.*	*Sq.Ft.*			*Per Connecting Evaluation table*

The parcel hosting building 1 is therefore identified as the most suitable parcel to host the plant as illustrated in Figure 14. Details of the subsequent conceptual system can be found in CHAPTER 8.

Figure 14: Results of Building Hosting/Connecting Evaluation



Cities and districts exploring district thermal energy for planned development can replicate the exercise above with real data or appropriate assumptions to similarly identify the role of each parcel in the greater scheme.

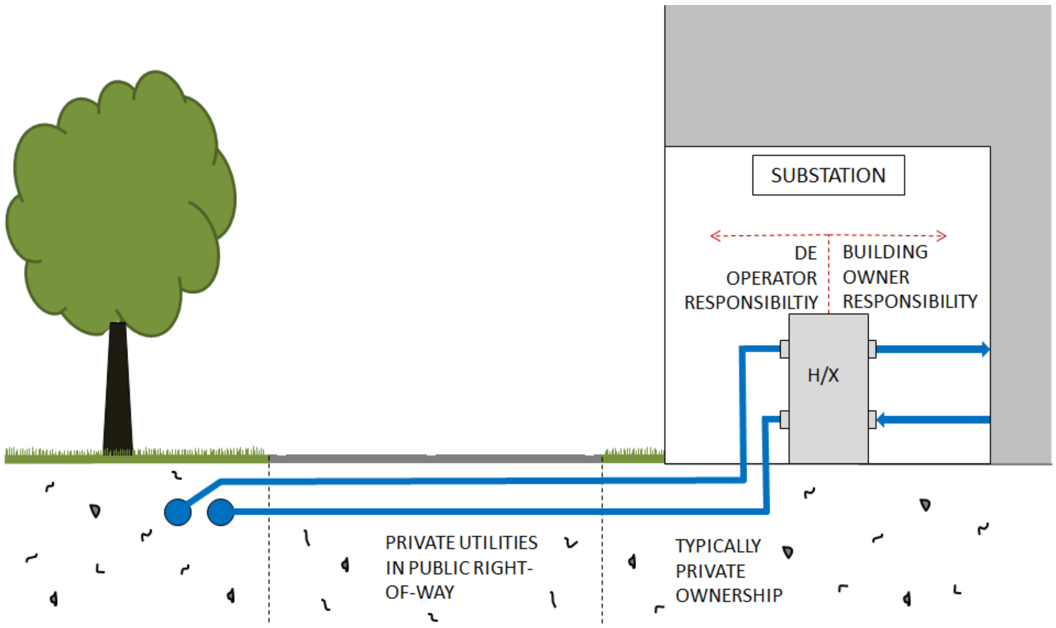
4.3 Points of Interconnection

District thermal systems span across various lines of ownership, use public rights-of-way to host private infrastructure, and cross-connect buildings of differing functions. There is therefore a high risk of gaps in scope and blurred lines of responsibility through all phases of planning, design, construction, and commissioning. If left unaddressed, these gaps can lead to an incomplete and possibly unsuccessful project. Active engagement from all stakeholders is therefore a critical element in ensuring these gaps are identified and resolved.

In most urban districts, the buildings connecting to the district thermal energy system will have unique and independent owners, whereas the CUP and distribution systems will be owned and managed by a district energy supplier. A variation of this model occurs when one of the buildings hosts the CUP, and the district energy system and the host building are subsequently owned by the same entity. The latter model was assumed for the indicative Flower Market district thermal energy system as described in Section 4.2.

Either model can raise questions about ownership and responsibilities. The most common arrangement is where the district energy supplier owns and maintains the equipment on the distribution side of the heat exchanger in the building ETS and the building owner is responsible for the system on the other side of the heat exchanger within the building, as illustrated by Figure 15.

Figure 15: Typical District Thermal Energy Responsibility Arrangement



During design, building owners should provide ETS design data to facilitate smooth installation and interconnection between the building and district energy systems. The district energy supplier might even provide a set of typical generic interconnection designs that the building owner could incorporate and/or adapt into the design of the building ETS. The district energy supplier should also provide rate, performance, and technical information pertaining to the district thermal system so that the building owner can make an informed decision about connecting.

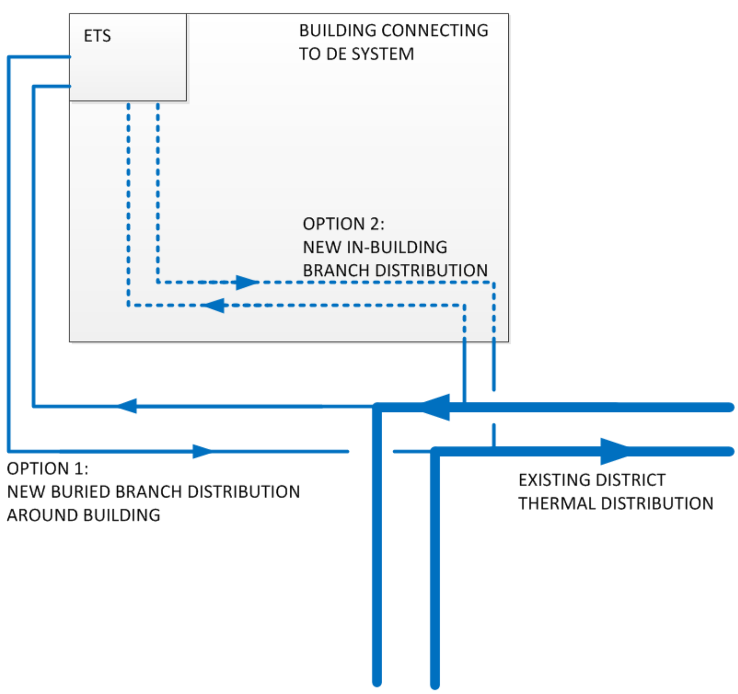
Communication and coordination pertaining to the location and design of the building ETS and the nearest section of distribution is crucial and can help minimize interconnection piping costs. For new developments, the building owner, architects, engineers, and the district energy supplier should collectively optimize the location of the ETS room and the routing of distribution pipes. In cases where the buildings and district energy system are built at the same time, the district energy system must be ready before the buildings become operational. Timing is especially crucial in such a scenario, and building owners often become nervous about making the decision to proceed with the design of their buildings without the inclusion of a building-level thermal energy plant.

One solution in this scenario is to proceed with design with the inclusion of a building-level thermal plant but incorporate appropriate fittings and valves into the design that allow the system to connect to a district energy system. This connection could be either at a future date or in lieu of a building thermal plant, should the district energy system become available as planned before the completion of the building.

Another common scenario occurs when a building owner is interested in connecting to a district thermal system but the system distribution is several years away from reaching the vicinity of the owners' building. The interconnection costs under this scenario could be prohibitively expensive, tempting the building owner to default to a building-level thermal energy plant rather than delaying the construction and occupancy of the building to a date when the system distribution is closer to the building. However, a common arrangement is for the district energy provider to lease the building owner primary heating and cooling equipment (such as boilers and chillers) to incorporate into a future-connection-ready building-level thermal energy plant. This lease then terminates once the district system distribution is within an agreed distance from the owner's building, at which point the owner would undertake a less expensive interconnection and return the primary heating and cooling systems to the district energy supplier.

For the connection of existing buildings, the location of the ETS room is important in identifying possible points of connection to the distribution network. In some cases, it might be less expensive to route distribution pipes through the building instead of around it, due to avoided trenching costs and a reduction in pipe insulation and jacketing costs as illustrated in Figure 16.

Figure 16: In-Building and Buried Distribution Interconnection Options



This will depend on the location of the ETS as well as the available space for additional distribution pipes. As in the case of new development, such solutions will require contracts describing responsibilities and access for inspection and maintenance.

During operation, the building owners will typically provide the district energy supplier with access to the ETS room to perform required maintenance, inspection, upgrades etc. The specific responsibilities for operation, performance, and maintenance of the different pieces of equipment are specified in the contract between the customer and the supplier.

The indicative Flower Market development studied in this task was assumed to consist of new buildings and a new central plant hosted within one of the buildings. The potential scope gaps for new buildings mentioned above therefore apply, especially for the phase 1 buildings.

4.4 Feasibility Conclusion

The feasibility study summarized in this Section suggests that a district thermal system serving the Flower Market area in the Central SoMa district of San Francisco is feasible and should be conceptualized in order to quantify the economic, social, and environmental benefits. The feasibility tools developed in the smart growth report suggest that the most suitable technology is central heating and cooling with heat recovery chillers, and that building 1 should host the central plant, while all other buildings should connect.

The subsequent conceptual study was completed as part of this report, and is summarized in CHAPTER 8. The benefits of the conceptual district thermal energy system were also studied, and are summarized in CHAPTER 9.

CHAPTER 5: Codes, Regulations, and Standards

This section provides a preliminary review of applicable codes, regulations and standards pertaining to the identified preferred district thermal technology. These are organized into the three main components of a district thermal system (primary heating and cooling systems, distribution, and building interconnections) and by phase (design and construction)

5.1 Central Utility Plant

The primary heating and cooling systems (located in the CUP) of the identified technology are no different than those housed in buildings under a distributed thermal energy scheme. These systems are governed by standard building codes including but not limited to the following:

- California Building Code (CBC)
- California Mechanical Code (CMC)
- California Plumbing Code (CPC)
- California Electrical Code (CEC)
- National Fire Protection Association (NFPA)
- National Electrical Code (NEC)
- International Building Code (IBC)
- America Society of Heating Refrigeration and Air Conditioning Engineers (ASHRAE) 90.1 standard for energy efficiency

Figure 17: Example of Primary Heating and Cooling Equipment in a Central Utility Plant

This report therefore does not document further investigation into codes, regulations, and standards for the primary heating and cooling system aspects of the overall system.

It should be noted however, that cities and districts exploring alternate primary heating and cooling systems such as co-generation will be subject to additional local air quality and emissions regulations. These regulations can be onerous if not identified early and if compliance is not planned at an early design stage.

It should also be noted that the code and regulatory implications for electrical distribution are covered in detail in the CIRE Task 2 report titled "Community-Distributed Generation (Regulatory Policy)" report, as well as outlined in the smart growth report, and therefore not restated here.

5.2 Distribution

The distribution components of a district thermal energy system are unlike standard distributed thermal energy systems. They generally involve privately owned, buried infrastructure such as pipes under private or publically owned land and/or streets. This involves civil, geotechnical, mechanical, and electrical design and construction in active and often publically accessible spaces. This report therefore explores applicable codes, regulations and standards for the distribution aspect of the identified district thermal energy technology during each of the design and construction phases.

Figure 18: Example Installation of Privately Owned District Thermal Distribution under Privately Owned Land

5.2.1 Design Phase

5.2.1.1 General

Design of underground utility work is generally not governed by a central code such as those that govern in building HVAC systems. Instead, codes and standards are specific to the agency that owns the system. Private institutions such as university campuses typically develop and maintain such specifications for all underground utility work, but in a public setting such as the SoMa Flower Market area, the design of the district thermal distribution system will have to comply with the utility or entity that will eventually own (and potentially operate) the system.

Cities and districts looking to explore district thermal systems should therefore engage potential system owner-operators soon after appointing a system design engineer to understand the details, standards, and specifications required for the design stage. Implications of these include but are not limited to aspects such as pipe materials, fittings, burial depth, and testing requirements.

5.2.1.2 Spatial Planning

Underground systems must be planned such that disruption to existing utilities is avoided. A detailed study of the site is therefore critical, and should take additional risks into account during construction. If no detailed soil temperature distribution study is possible, it is recommended to separate heating distribution systems from other utilities leave at least 15 feet between heating systems and other utilities of plastic components.[7]

5.2.1.3 Pipe Material, Insulation and Protection

Design standards for district thermal distribution systems vary to a certain extent, but pre-insulated steel pipes with waterproof jacketing are fairly common. High Density Poly Ethylene (HDPE) pipes are not uncommon and offer a less expensive and more flexible means (especially at small diameters) of constructing a distribution network. However, HDPE pipes tend to have lower operating pressure and temperature limitations than steel and should be studied on a case by case basis.

In addition to pre-insulation, pipe manufactures also offer pre-installed leak detection systems which tend to increase material costs, but reduce field costs as they eliminate the time and labor required to install a separate leak detection system.

[7] *District Heating Guide*. ASHRAE. 2013

Figure 19: Example of Pre-Insulated, Pre-Installed Leak Detection District Thermal Steel Pipes Staged at a Construction Site

Insulation thickness depends on the temperature difference between the water in the pipes and the temperature of the surrounding environment. Insulation thickness guidelines and specifications are typically informed by an economic analysis that compares the reduced costs for thermal losses against the increased material costs.

The potential presence of groundwater and moisture content in soil affects the thermal properties of insulation, and it is therefore important to keep the insulation dry. For low-temperature systems there are a broad selection of efficient insulation materials and inexpensive pipe materials.

Metal pipes also need to be protected from corrosion caused by soil. A common method to protect pipes against corrosion is through cathodic protection, which generates a reverse voltage strong enough to stop the corrosion. Connection points to a cathodic protection system are typically located in manholes or valve vaults as described in 5.2.1.7. Valve vaults also give the possibility to isolate a smaller part of the system, which can be useful both during routine maintenance and for addressing operational issues.

5.2.1.4 Pipe Wall Thickness

Pipe wall thickness is determined by the maximum operating temperature and pressure of the system. Low-temperature systems enable the use of pipes with thinner walls which not only off-set the increased costs associated with larger diameter pipes that are required by low-temperature systems, but decrease expansion forces. This results in simpler expansion compensation requirements and further reduces costs. However, pipes with thinner walls may require additional inspection and extra care due to lower corrosion allowance.

5.2.1.5 Pipe Sizing

Pipe sizing is usually determined by maximum flow velocity and/or pressure drop constraints. Proper sizing of the pipes is important to strike the optimal balance between increased pumping costs, erosion problems, and noise levels should pipes be too small, and increased first costs and spatial requirements should pipes be too large.

There are various standards for hydronic pipe sizing. The ASHRAE fundamentals handbook[8] is a common source for pipe sizing guidance, and provides the following guidance on pipe sizing:

- Velocity should be limited to 4 feet per second (fps) for pipes that are 2 inches or less in diameter.
- Pressure drop should be limited to 4 feet per 100 feet for pipes that are greater than 2 inches in diameter.

5.2.1.6 Thermal Expansion

Thermal distribution piping expands and contracts due to temperature changes in the system. It is therefore necessary to design the system so that these movements can be absorbed in order to prevent failures due to high stress and/or fatigue of the pipes as well as forces and stress on equipment connected to the pipes. Turns and bends are typically designed into distribution to provide flexibility in the system. Expansion loops are commonly used in cases where there are long runs of straight pipe and not enough turns or bends in the overall system to provide adequate expansion capability.

Expansion loops require extra space and as such additional right-of-way will be required. In places with spatial constraints, other mechanical methods, like expansion joints or ball joints, are used.

5.2.1.7 Maintenance Access

It is required to provide manholes in order to facilitate access to the underground pipes, especially at critical points such as major branches with isolation valves. It is recommended to provide manhole access points not farther than 500 feet apart to facilitate appropriate leak detection, location, and repair. Manholes should be large enough for the maintenance personnel and equipped with an electric sump pumps or be drained to a sanitary system. For safety reasons, pipes and equipment must be placed in a way that allows easy access for maintenance and makes it possible for personnel to quickly exit in case of an emergency.

The weakest points in a distribution system are usually the joints between piping and fittings. Since the joining of piping must be executed at the construction site, it is especially important to control the quality of these parts of the system in order to avoid leakages.

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[8] *2013 Fundamentals*. ASHRAE Handbook. 2013

Figure 20: Example of Fusion Welding at a Pipe Joint (an Appropriate Location for an Access Manhole)

5.2.2 Construction Phase

5.2.2.1 General

Two general sets of codes and standards apply during construction. The first is for the actual materials, and construction and testing procedures for which the project specifications will typically reference back to national standards including the following:

- America Society for Testing and Maintenance (ASTM) standards
- American Society of Mechanical Engineers (ASME) standards
- American Welding Society (AWS) standards

Figure 21: Example of a Bypass Arrangement for Distribution Testing

The second set of codes and standards will relate to carrying out construction activities in public streets and relates primarily to traffic mitigation, lane closures, truck rerouting, etc.

5.2.2.2 Trench Excavation and Distribution Installation

When installing the distribution system the trenches must be over-excavated, in order to facilitate the construction work and protect the pipes from being damaged by for example rocks or construction equipment. Typically the trench needs to be over-excavated by at least 4 inches in depth in order to protect the pipes from damaging material.[9] Sometimes more working space is required, for example for welding of the pipe joints, and further over-excavation of the trench may be needed. The over-excavation is normally filled with a backfill material consisting of a sandy material without any larger stones.

[9] *District Heating Guide*. 2013

Figure 22: Example of Excavation and Pipe Installation

5.2.2.3 Public Street Disruption

In addition to the buried distribution itself, the construction of the system will also require digging up and rebuilding of public streets and sidewalks. The engineer will therefore also have to prepare a set of drawings based on the city's standards for repair, restoration, and/or replacement of public streets, paving, striping, and trench and landscape restoration. These plans will be reviewed and approved by the appropriate city department.

In the case of the Central SoMa Flower Market area, the San Francisco Department of Public Works (SFDPW) would review this set of drawings.

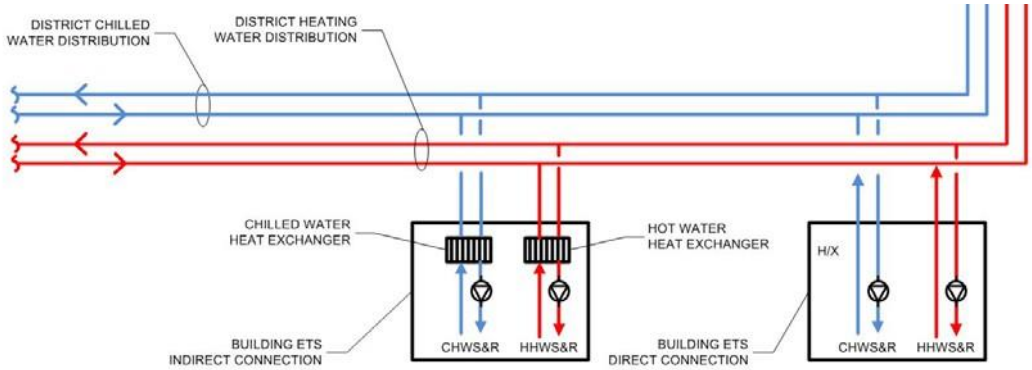
5.3 Building Interconnections

The building interconnection components (located within each building) of the identified technology are no different than those housed in buildings under a distributed thermal energy scheme. The codes and regulations identified in Section 5.1 are therefore applicable to this section as well.

There are broadly two standard methods for connecting buildings to a district energy system; direct connections and indirect connections.

A direct connection means that energy is delivered to the building directly without a decoupling device such as a heat exchanger. An indirect connection, which is most common in modern systems, means that the energy is delivered to buildings through heat exchangers. In indirect systems, water used in the district energy system therefore does not mix with the water of the building system.

Figure 23: Indirect and Direct Building Interconnections



Indirect systems are advantageous because the network and the building are two separate systems, which makes the contractual administration easier is terms of ownership, operation, and maintenance. It also makes it possible to design the network without concerns for pressure and temperature limitations in buildings.

The main drawback of indirect systems is the temperature loss across the heat exchanger, which may increase pumping costs and costs for larger heat exchangers (especially in cooling networks due to low delta Ts). Indirect systems also require that every building operate and maintain chemical treatment systems for the building systems, while the district system operator maintains water chemistry for the district system. Table 10 summarizes the pros and cons of direct and indirect building interconnection systems.

Table 10: Indirect and Direct Connection Comparison

Pros	**Cons**	**Pros**	**Cons**
No losses between systems **Single water treatment system**	Complex contracting and system administration Risk of district system leaking into building Lack of clear O&M boundaries System and building pressure and temperature dependence	Simplified contracting and system administration Clear O&M boundaries System and building pressure and temperature independence	Losses between systems at heat exchanger Multiple water treatment systems required

The interconnection between the district energy system and the building system is often referred to as a "substation" and also an Energy Transfer Station (ETS). The ETS houses the heat exchangers and building system pumps that extract energy from the district system, and supply it to the building systems.

Energy storages are not required but can be installed to ensure resilience in critical cases, for example in hospitals. By not using domestic hot water storage the risk of growth of legionella bacteria is decreased and the efficiency across the heat exchanger is increased. Efficient heat exchangers in the consumers' ETSs (resulting in low return temperature) are important for an efficient district energy system.

For the purposes of this report, the conceptualization of the district thermal system serving the Flower Market site includes indirect building interconnections.

CHAPTER 6: Permits

6.1 Design Phase

Two approvals are generally required during the design phase of a district thermal energy project. The first is directly from the agency that will own (and likely operate) the system such as a private utility or the community created ownership entity. The second is the permit from the city for street restoration as described in Section 5.2.2.3.

6.2 Construction Phase

With the design approvals in hand, the contractor will need a permit to do work in the public right-of way (an encroachment permit). This permit requires the preparation of items such as traffic control plans, staging and stockpiling plans, haul route maps, and a Storm Water Pollution Prevention Plans (SWPPP). Together, these documents constitute the overall temporary works plan under which (if approved) the encroachment permit is granted.

According to the San Francisco Administrative Code Chapter 11, a franchise agreement must also be granted by ordinance of the City's Board of Supervisors to construct, install, or operate facilities in the public right-of-way or to provide services using facilities installed in the public rights-of-way. People that only use the facility for providing service to themselves, and not to any third parties on a commercial basis, are exceptions to this franchise requirement.

As part of the franchise agreement, a fee must be paid to the City. The fee is typically a percentage of gross revenues or some other measure. The applicant must also pay a proposal fee to the City, which should include all reasonable costs related to the processing of the proposal.[10]

Additionally, installing, repairing, or replacing utilities within a public right-of-way will entail excavating and restoring sidewalk and roadway pavement. A General Excavation permit issued by the Department of Public Works is required for this aspect.[11]

For future maintenance of the distribution system, Temporary Occupancy Permits are required for working in and around any manhole (according to the San Francisco Public Works Code, Article 15, Section 724).[12]

[10] San Francisco Administrative Code. Chapter 11: Franchise.

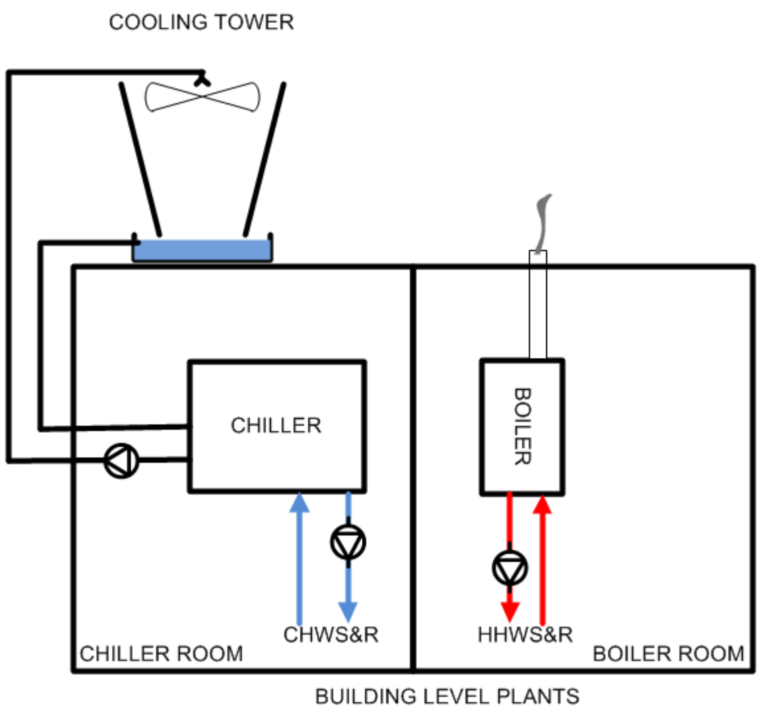
[11] "Permit." City & County of San Francisco Department of Public Works. accessed August 15. 2014. http://sfdpw.org/index.aspx?page=1597.

[12] "Permits."

CHAPTER 7:
Baseline Thermal System

An appropriate baseline scheme is required in order to assess the performance of the conceptual Flower Market district thermal energy scheme. As described in Section 2.2.1, developer led buildings in the study area would generally include central chilled water and heating water plants, a simple illustration of which is provided in Figure 24.

Figure 24: Baseline Building Level Thermal Plants



The following steps were followed in order to establish the spatial, capacity and cost implications, as well as the system performance for these plants:

- The peak loads established in Section 3.3.1 were used to size the plants for each building.
- The loads coupled with redundancy considerations were used to generate equipment sizes and quantities.
- A standard structural grid size of 20′ x 30′ was assumed for chiller and boiler room spatial planning.
- Access and maintenance considerations were made for layout purposes to generate spatial requirements.
- The IES VE energy model was used to generate the load distribution for each building.
- The DEF model was used to assess the energy, water and carbon performance of the baseline scheme.

The resulting equipment sizes and quantities are summarized in Table 11.

Table 11: Baseline Building Thermal Plant Equipment

Building	Equipment	Unit	Capacity	Quantity
1	Electric Chiller	tons	800	3
	Cooling Tower	tons	1000	3
	Condensing Boilers	MMBH	5	3
2	Electric Chiller	tons	150	3
	Cooling Tower	tons	300	2
	Condensing Boilers	MMBH	2	2
3	Electric Chiller	tons	300	2
	Cooling Tower	tons	350	2
	Condensing Boilers	MMBH	2	2
4	Electric Chiller	tons	550	2
	Cooling Tower	tons	650	2
	Condensing Boilers	MMBH	5	1
	Condensing Boilers	MMBH	2	1
5	Electric Chiller	tons	300	2
	Cooling Tower	tons	350	2
	Condensing Boilers	MMBH	3	1
	Condensing Boilers	MMBH	2	1
6	Electric Chiller	tons	100	2
	Cooling Tower	tons	150	2
	Condensing Boilers	MMBH	2	1

Figure 25 and Figure 26 illustrate the baseline plant layouts for buildings 1 and 5, respectively.

Figure 25: Building 1 Baseline Plant

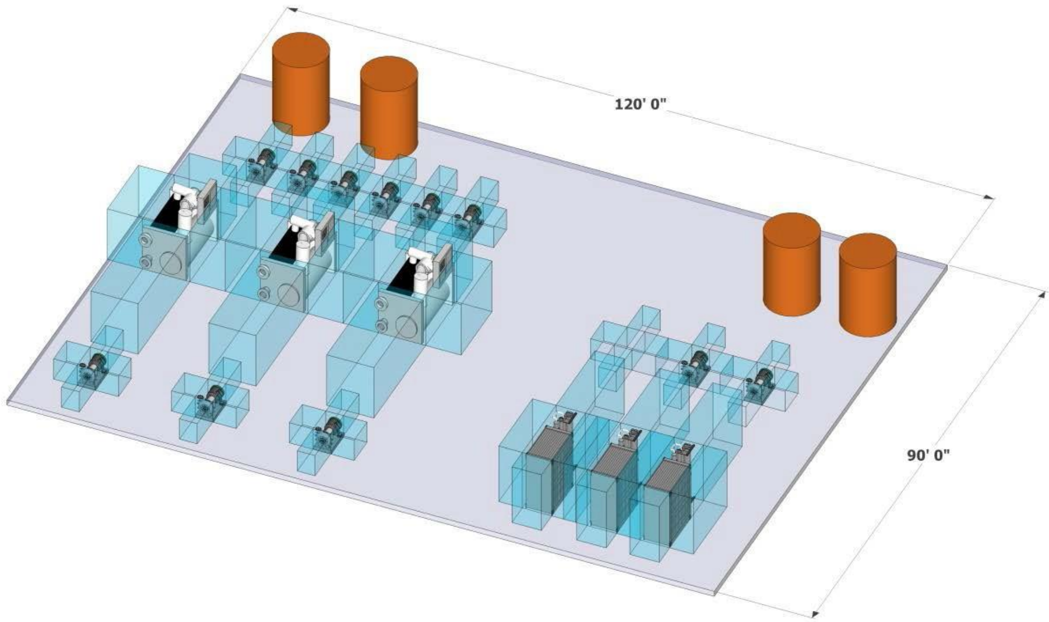
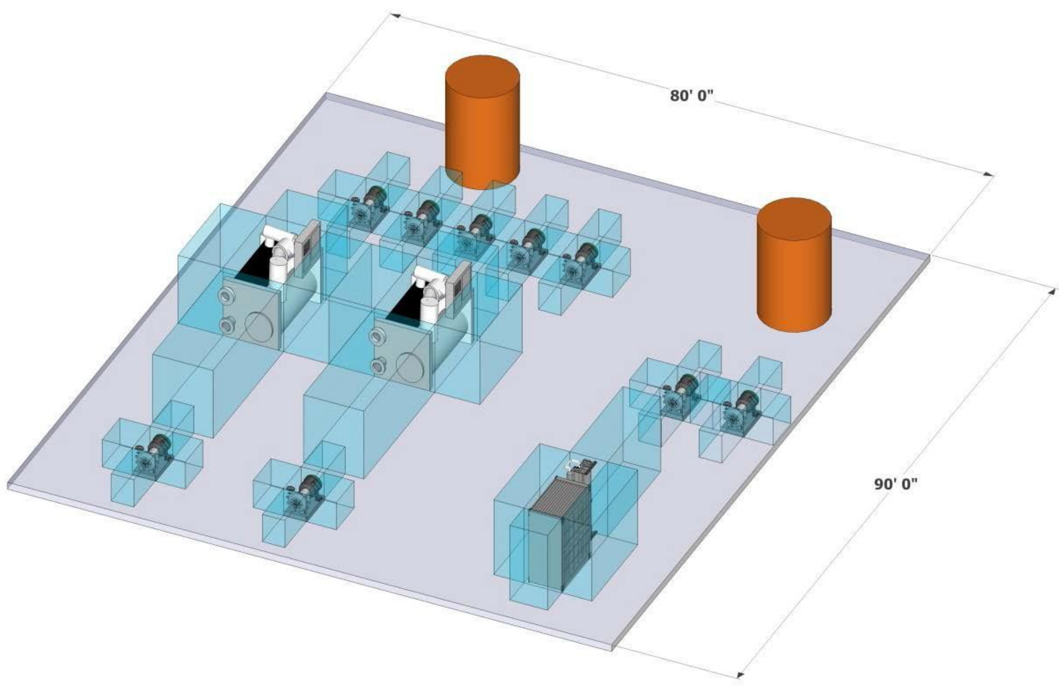
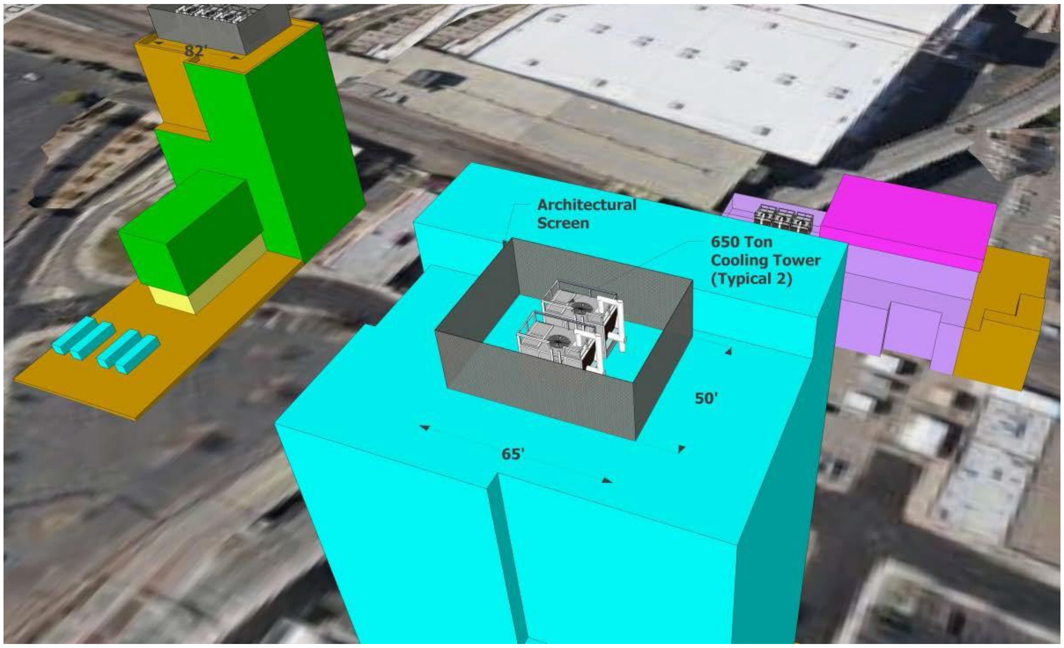


Figure 26: Building 5 Baseline Plant



Similar equipment layouts were created for the plants in buildings 2, 3, 4, and 5, as well as for rooftop cooling towers in each building. An example of a rooftop cooling tower layout is provided for building 4 in in Figure 27 as an example of these layouts.

Figure 27: Building 4 Rooftop Cooling Tower Spatial Requirements



The plant and rooftop equipment spatial requirements generated using these studies are summarized in Table 12.

Table 12: Baseline Plant and Cooling Tower Area Requirements

Building	Plant Area (ft^2)	Roof Area (ft^2)
1	10,800	4,250
2	9,000	2,700
3	9,000	2,700
4	7,200	3,250
5	7,200	2,700
6	5,400	2,700
Subtotal	**48,600**	**18,300**
Total	**66,900**	

CHAPTER 8:
Conceptual District Thermal System

This section contains the details of the district thermal system conceptualized for the Flower Market area, which are as follows:

- An overview of the system is provided in Section 8.1.
- The central plant equipment and configuration are provided in Section 8.2.
- The distribution is described in Section 8.3.
- The building interconnections or ETSs are described in Section 8.4.
- The potential of CIRE for this conceptual system is explored in Section 8.5.

8.1 Overview

As summarized in Section 4.1, central heating and cooling with heat recovery chillers was the district thermal energy technology selected to serve the indicative development at the Flower Market area.

Also known as SHP, this scheme capitalizes on the mild San Francisco climate which allows the use of low-temperature systems. By reusing unwanted heat from spaces demanding air conditioning into spaces concurrently demanding heat, this technology also capitalizes on the mix of commercial, retail, and residential buildings which have complimentary use schedules. The potential for year-round low-temperature heat recovery for the Flower Market is illustrated in Figure 28.

Figure 28: Flower Market Average Day Heat Recovery Operation

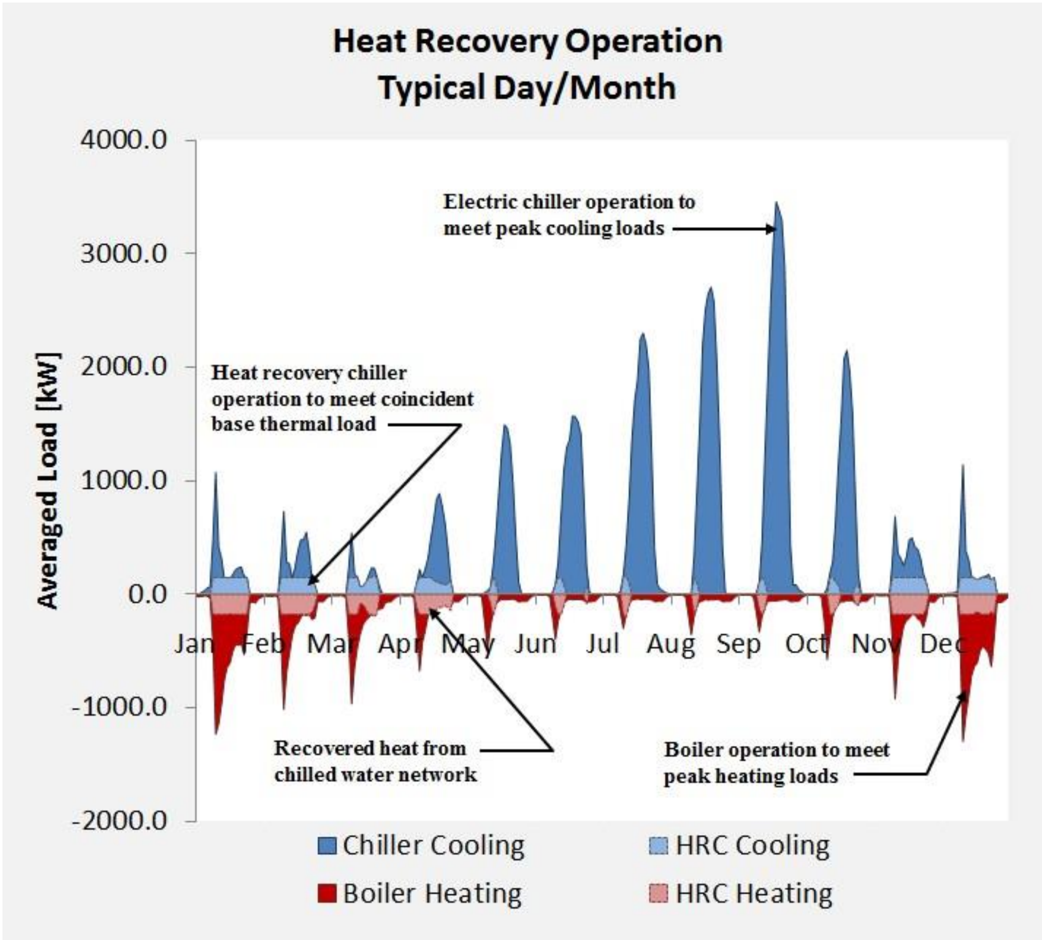


Figure 29 provides an overall system schematic for the technology, and **Figure 30** provides a detailed view into the components within the CUP.

Figure 29: Overview of Selected District Thermal Energy Technology

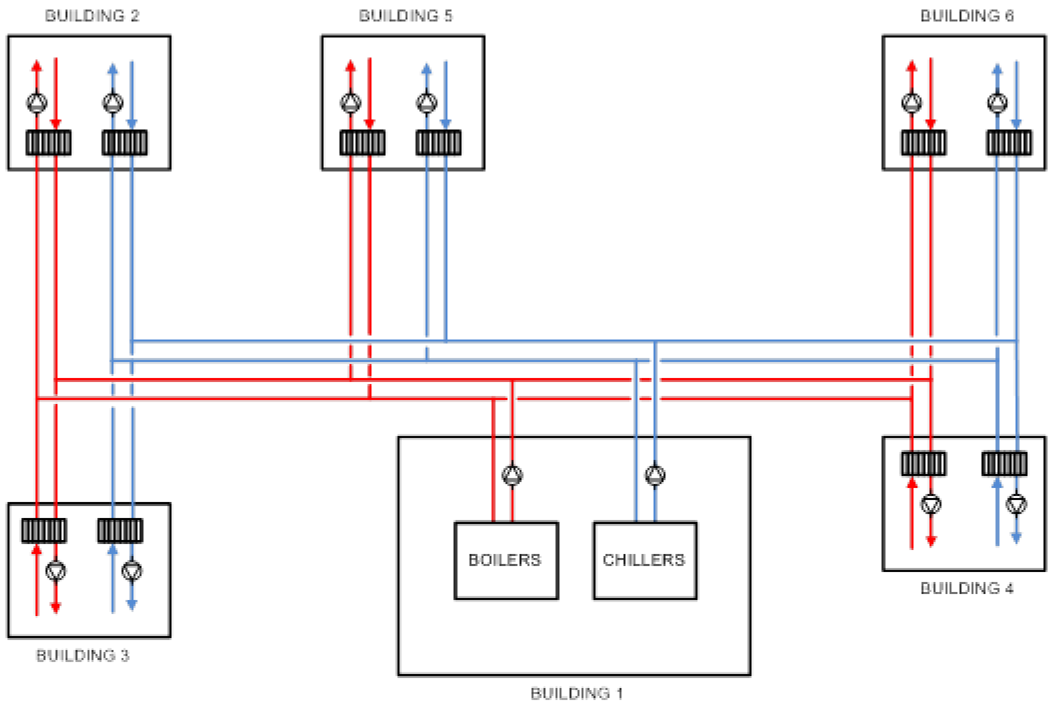
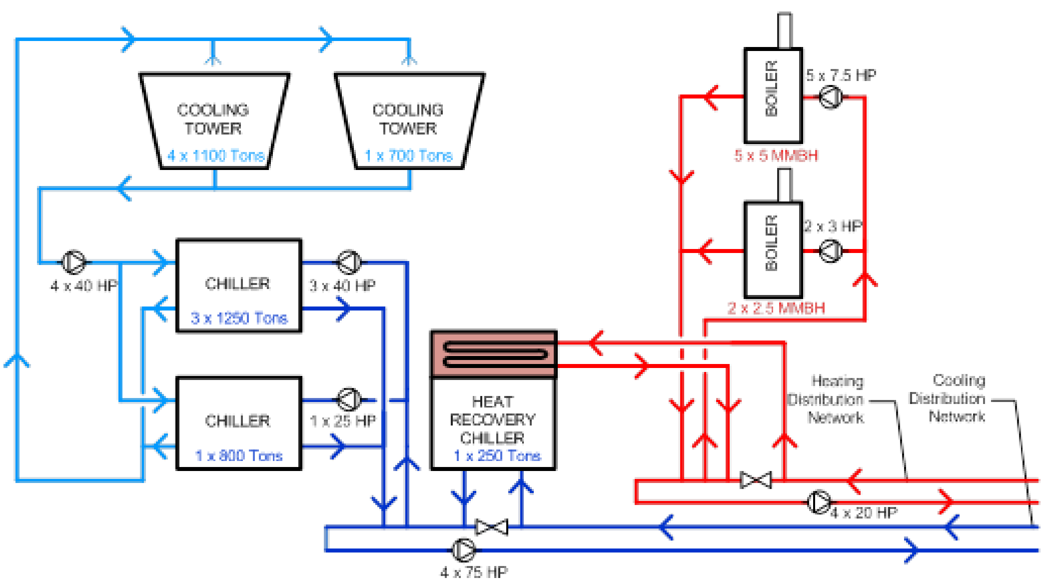


Figure 30: Detail of District Thermal CUP Components



8.2 Central Utility Plant

As summarized in Section 4.2, building 1 was identified as the most feasible building to host the CUP. This implies that building 1 will include mechanical space to host not only the capacity of primary heating and cooling systems needed to meet its own loads, but also the loads of buildings 2 and 5 as early as 2018, and the loads of buildings 3, 4 and 6 by 2022.

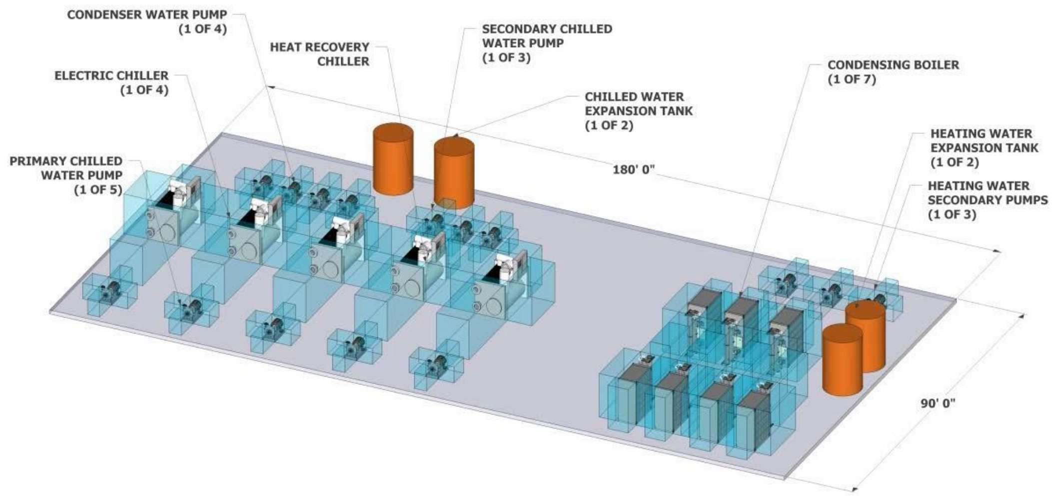
The equipment quantities and capacities required in the building 1 CUP are summarized in Table 13.

Table 13: Central Utility Plant Primary Heating and Cooling Equipment

CUP Equipment	Unit	Capacity	Phase 1 Quantity	Phase 2 Quantity	Total Quantity
Electric Chiller	tons	800	1	0	1
Electric Chiller	tons	1,250	2	1	3
Heat Recovery Chiller	tons	250	1	0	1
Cooling Tower	tons	1,100	3	1	4
Cooling Tower	tons	700	0	1	1
Condensing Boilers	MMBTU	5	3	2	5
Condensing Boilers	MMBTU	2	2	0	2

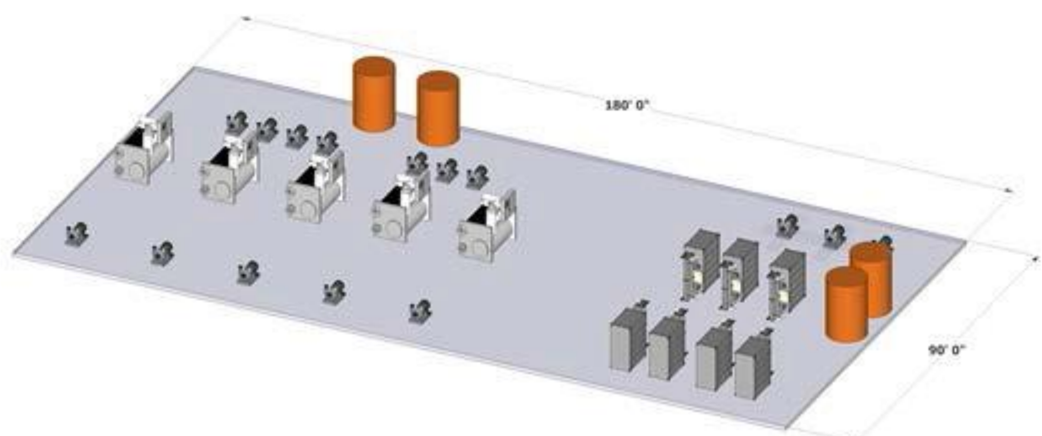
Figure 31 is a layout of this equipment using the same considerations as in the baseline plants (including a standard 20ft x 30ft structural grid) and suggests that ultimately a 16,200-square-foot space is required in building 1 to host the CUP equipment. This space would ideally be located on lower levels such as level 1 or a basement level, or within a rooftop mechanical penthouse.

Figure 31: Indicative District Thermal Energy Plant



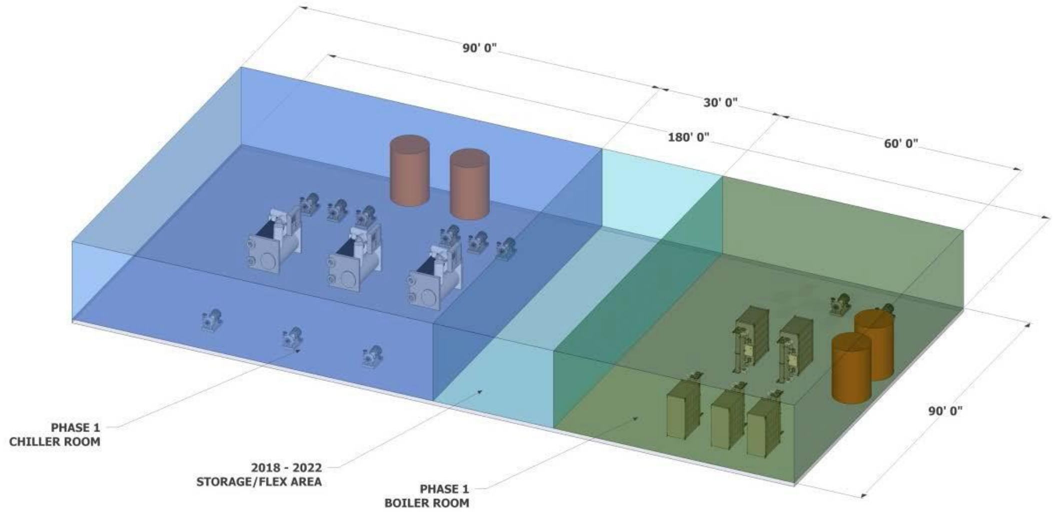
Note that Figure 31 physically shows the access, clearance, and maintenance space required in light blue, in addition to the equipment itself. Figure 32 illustrates the layout of equipment without physically showing the clearance spaces.

Figure 32: Indicative District Thermal Energy Plant without Equipment Clearances



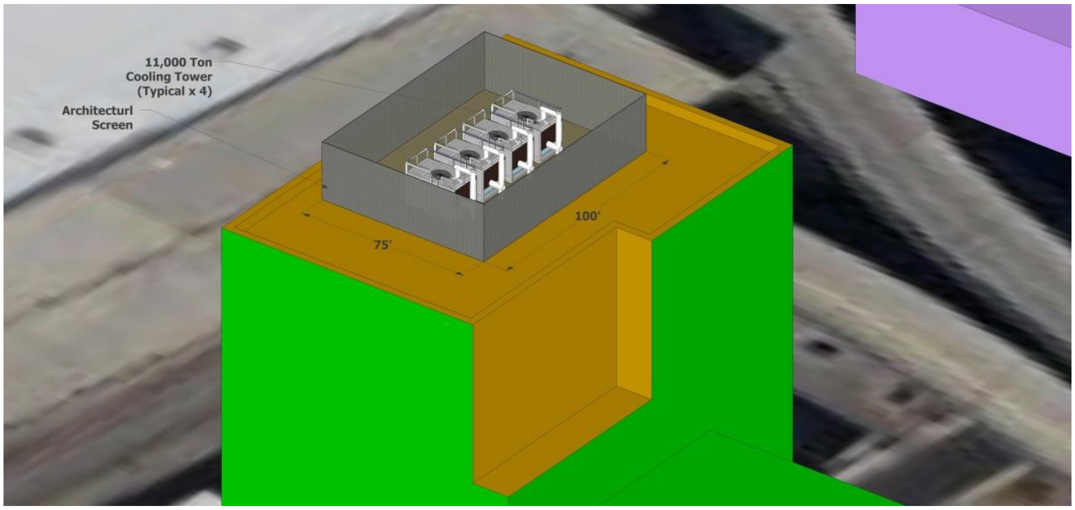
A similar layout was created for the phase 1 equipment as illustrated in Figure 33 and suggests that approximately 2,700ft^2 of space reserved for the ultimate plant can be utilized in the interim (between 2018 and 2022) as flex-space, storage space, or similar.

Figure 33: Phase 1 Indicative Plant Spatial Requirements



Additional space on the building 1 roof or in an adjacent yard would also be required to house cooling towers. A layout based on the capacities in Table 13 was created to estimate this requirement, and is illustrated in Figure 34.

Figure 34: Building 1 (CUP) Rooftop Cooling Tower Spatial Requirements



The total plant and rooftop space required for the district thermal energy scheme primary heating and cooling equipment in building 1 is summarized in Table 14.

Table 14: District Thermal Energy Primary Heating and Cooling Equipment Area Requirements

Space	Phase 1	Phase 2	Total
	ft^2	ft^2	ft^2
Plant Space	13,500	2,700	16,200
Cooling Tower Rooftop/Yard Space	3,600	3,900	7,500
Total	**17,100**	**6,600**	**23,700**

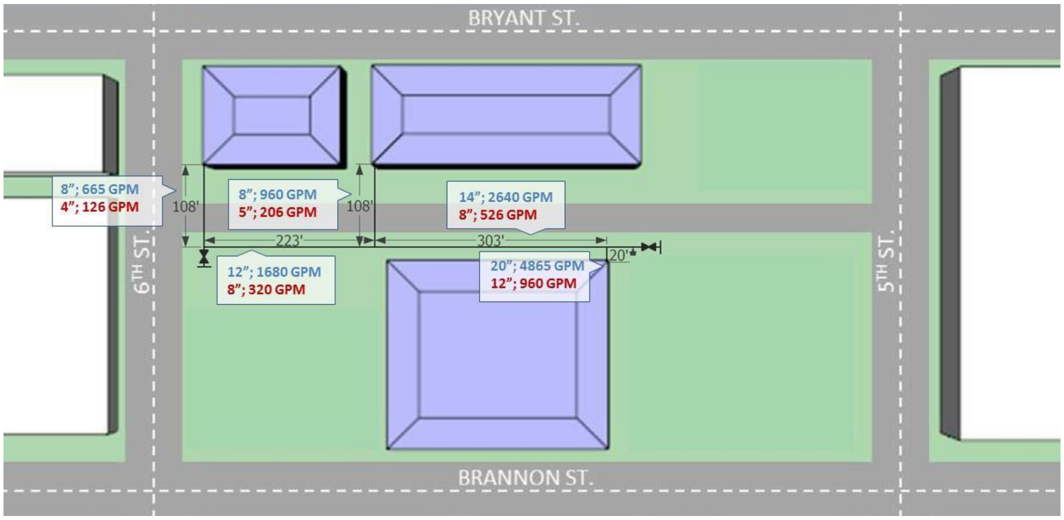
8.3 Distribution

The distribution for a central heating and cooling system with heat recovery chillers comprises of a 4-pipe buried distribution system that comprises the following pipes:

- chilled water supply
- chilled water return
- heating water supply
- heating water return

During phase 1, the excavation and pipe construction works described in Section 5.2 will need to be carried out to connect the CUP in building 1 to the other phase 1 buildings (buildings 2 and 5). Figure 35 shows the indicative trench lengths and pipe diameters required for at the completion of phase 1.

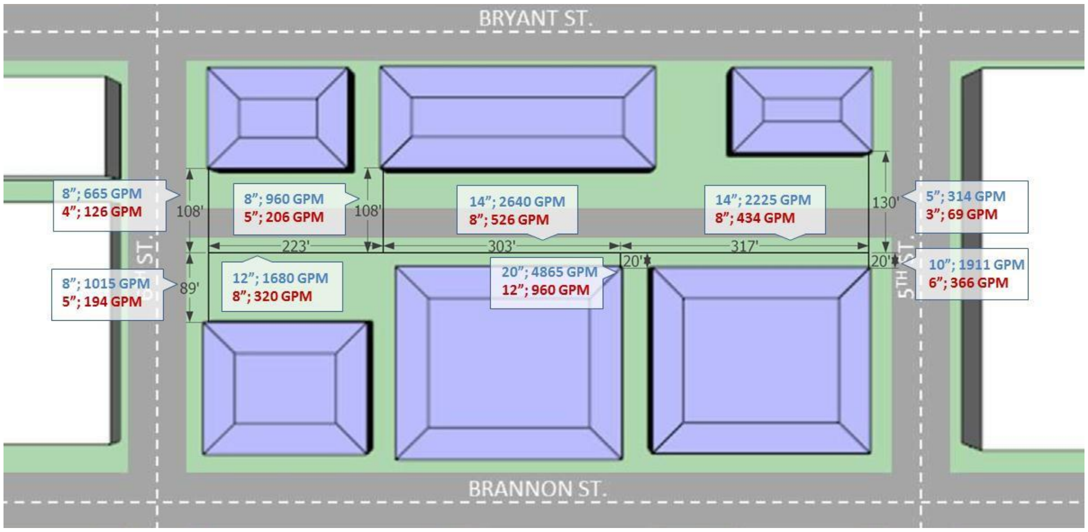
Figure 35: Conceptual District Thermal System Distribution at Phase 1



The design and construction of phased distribution typically entails the inclusion of stub out connections, the valve of which are shut and capped for future distribution expansion. Figure 35 also indicates the likely locations for these stub connections during phase 1.

During phase 2, the excavation and pipe construction work will resume where the phase 1 works left off. The phase 2 buildings (buildings 3, 4 and 6) will be connected to the phase 1 distribution at the stub connections, the valves of which will then be opened to allow flow to phase 2 buildings. Figure 36 shows the complete distribution system at the end of phase 2.

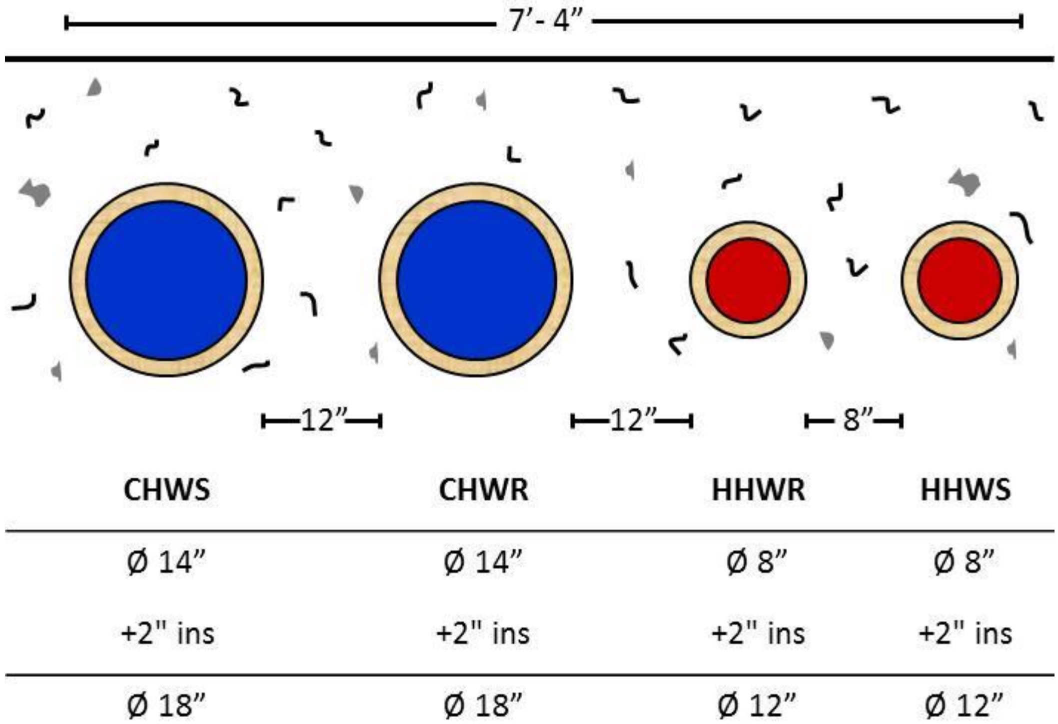
Figure 36: Conceptual District Thermal System Distribution at Phase 2



As described in Section 5.2, distribution pipes are buried with space between each other to allow for access and thermal isolation. As such, larger pipes require greater spacing between pipes, and overall trench widths get significantly larger than pipe dimensions alone might suggest.

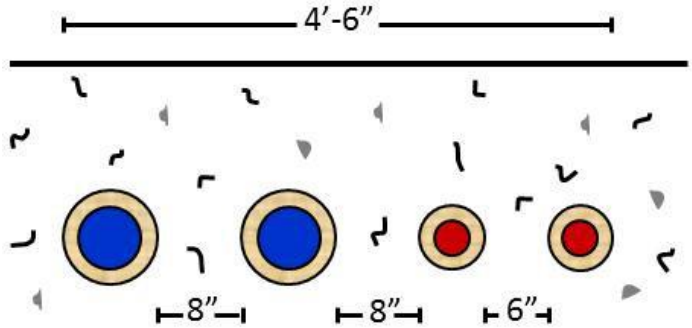
Figure 37 shows a cross section of an example layout for the main east-west distribution trunk seen running parallel to Brannon and Bryant streets in Figure 36. This example shows that the total trench width needed for a 4-pipe system, including pipes, insulation, and separation between pipes approaches 8 feet.

Figure 37: Space Requirements for Main Distribution Trunk



As a comparison, a cross section of an example layout for the building 6 branch pipes is provided in Figure 38. The building 6 connections represent the smallest diameter pipes in the conceptual distribution, and as Figure 38 suggests, the required trench width in this area can be reduced to 4.5 feet.

Figure 38: Space Requirements for Building 6 Connection



CHWS	CHWR	HHWR	HHWS
Ø 5"	Ø 5"	Ø 3"	Ø 3"
+2" ins	+2" ins	+2" ins	+2" ins
Ø 9"	Ø 9"	Ø 7"	Ø 7"

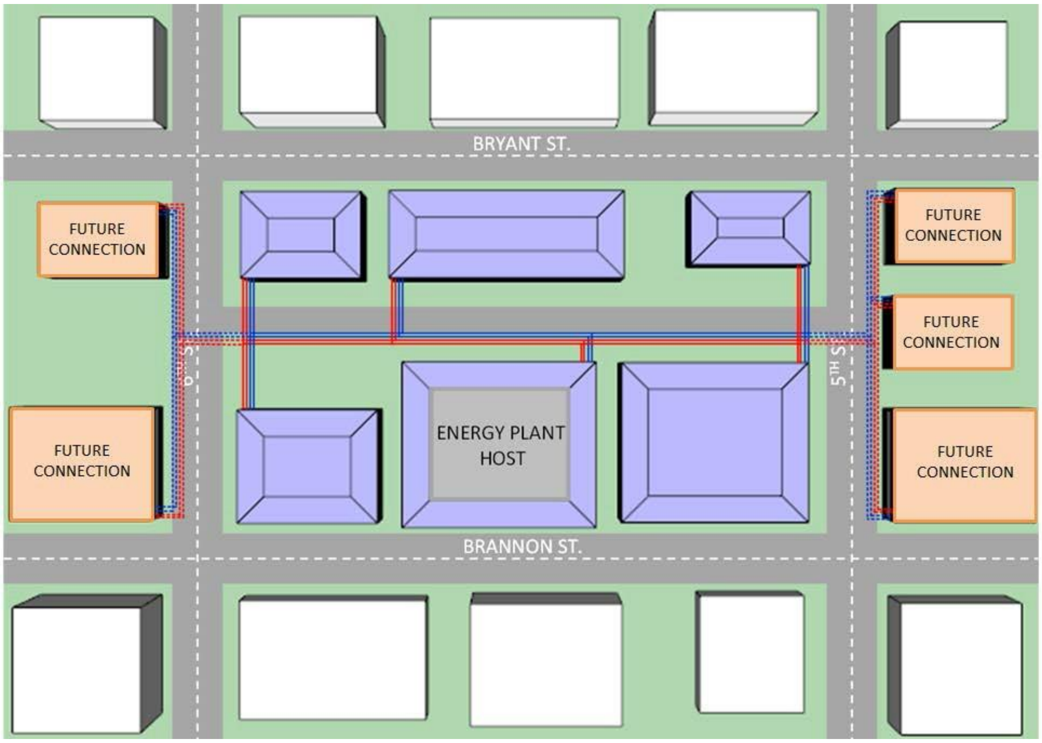
The conceptual design for the distribution includes an incremental up-sizing of the main CUP and distribution spine sections of pipe to allow for expansion in the future. This builds in the flexibility to connect additional buildings to the district thermal system in the future, without having to excavate and replace pipe. The value add for this design is that the district energy supplier can service additional revenue generating customers for the minor cost premium represented by two incremental pipe sizes, which is far less than the costs associated with excavation and pipe replacement.

By upsizing the main CUP and spine distribution sections, the Flower Market district energy scheme could potentially add the following:

- two additional buildings of scale similar to building 3
- three residential buildings of scale similar to building 6

Figure 39 illustrates the potential future building connections.

Figure 39: Potential Future Building Connections



Note: The addition of future buildings requires the addition of generation capacity (primary heating and cooling equipment) within the CUP. However, this is far less complex and expensive compared to replacing buried distribution.

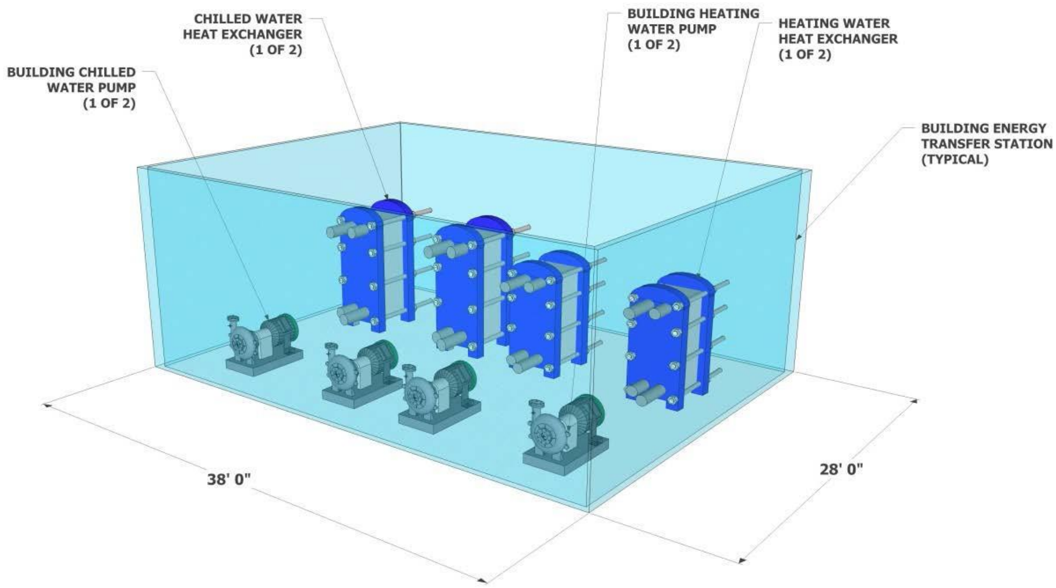
8.4 Building Interconnections

As described in Section 5.3, indirect building interconnections (or indirect ETSs) were assumed for the district thermal concept. Two heat exchangers each sized at 60% of the full building flow were used for each of the chilled water and heating water interconnections. This strategy provides each building with the flexibility to service and clean heat exchangers during low load conditions while maintaining the ability to meet up 60% of the building load.

Other ETS elements such as flow and energy metering devices, control valves, and other flushing/draining devices do not drive spatial requirements, and so were only considered for cost estimate purposes.

A typical layout for the above described building interconnections is illustrated in Figure 40.

Figure 40: Typical Flower Market Building Energy Transfer Station



The typical layout accounts for access and maintenance space that is consistent with the assumptions made in the central plant, as well as in the business as usual scheme summarized in CHAPTER 7.

ETS equipment sizes and quantities for each of the 6 indicative buildings in the Flower Market development are summarized in Table 15.

Table 15: ETS Equipment Summary

Building	Chilled Water Heat Exchangers		Heating Water Heat Exchangers	
	Flow (gpm)	Quantity	Flow (gpm)	Quantity
1	2260	2	430	2
2	400	2	80	2
3	610	2	120	2
4	760	2	220	2
5	580	2	120	2
6	190	2	40	2

The typical ETS layout illustrated in Figure 40 suggests that a floor area of approximately 1,000ft^2 is required for a 2 heat exchanger per utility design, which is used for all buildings.

8.5 CIRE Penetration

District thermal energy systems not only have the ability to reduce energy, water and peak loads as explored in Section 9.2, but can also enable deep CIRE penetration. This is due to the aggregation of a community's loads which results in the need for thermal supply systems at a larger scale than that required at individual buildings. This scale unlocks the potential for alternate and renewable fuels, as well as renewable and renewable ready technologies which are less feasible at the scale of a single building.

The following sections explore some of the CIRE technologies that could be integrated into the district thermal system conceptualized for the indicative Flower Market area community.

8.5.1 Solar Photovoltaics

Each of the buildings in the indicative community can still pursue solar PV as they would under the baseline thermal energy scheme. However, the district thermal scheme improves the value proposition of these solar PV systems in two ways.

First, consolidating a significant portion of each building's electrical load (associated with the chiller and boiler plants) to the CUP allows the solar PV systems to effectively contribute a larger renewable fraction of the each building's electricity consumption.[13]

Secondly, the reduction of mechanical equipment and penetrations at building rooftops will mean that each of the buildings can pursue larger PV systems, allowing an even greater renewable supply fraction.

Table 16 summarizes the assumptions and results for an indicative study exploring this synergy between district thermal energy and rooftop solar PV systems for the Flower Market development.

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[13] This will be true for all buildings in the community except for the building hosting the CUP.

Table 16: Indicative Solar PV and District Thermal Energy Synergy Study Assumptions

Building	Roof Area (ft²)	PV Area (ft²)		Peak Power Output (kW)		Electrical Output (MWh/yr)		Change (%)
		Baseline	DE	Baseline	DE	Baseline	DE	DE
1	67,200	21,568	15,825	388	285	551	404	-27%
2	23,400	5,985	9,945	108	179	153	254	66%
3	35,700	10,905	15,173	196	273	279	388	39%
4	67,200	22,818	28,560	411	514	583	730	25%
5	45,500	14,825	19,338	267	348	379	494	30%
6	19,800	4,545	8,415	82	151	116	215	85%
Total						**2,061**	**2,486**	**21%**

Additional assumptions pertaining to Table 16 include the following:

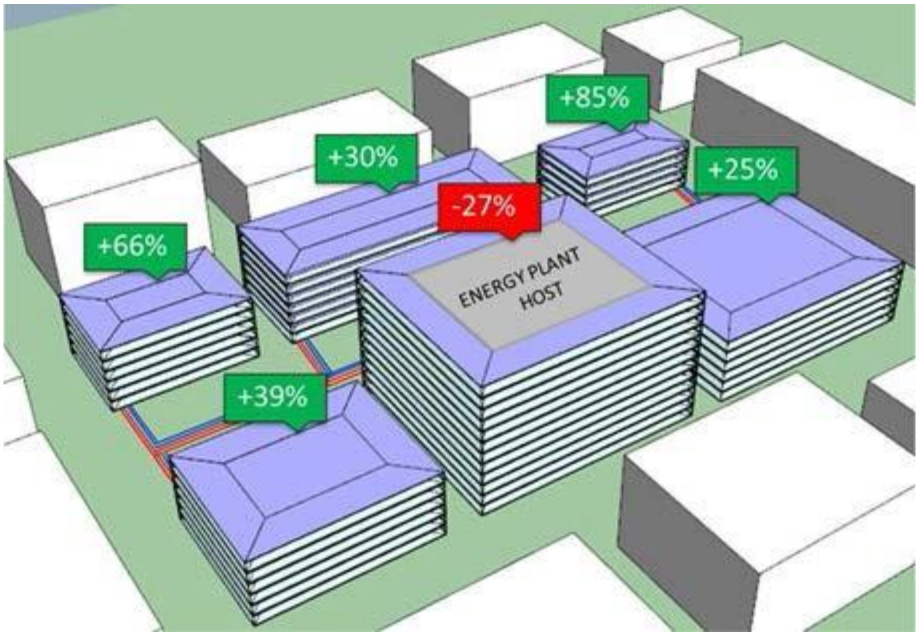
- The cooling towers were assumed to cover and shade 2.5 times their dimensions.
- In the baseline 20% of the roof is assumed to be unavailable for PV systems due to boiler flues, window washing equipment, elevator machine rooms, and stairs.
- In the district energy scenario, the unavailable roof area is reduced to 15% for the connecting buildings and increased to 25% for the energy plant host.
- The peak power output is assumed to be 18 W/ft².
- The electrical output for this type of PV panels in San Francisco is 1,420 kWh/kW/yr.[14]

This indicative study shows that by connecting to a district thermal energy system, buildings can achieve a greater renewable electrical energy supply fraction from rooftop solar PV systems. It also indicates that though the building hosting the CUP sees the opposite result (due to greater cooling tower roof coverage), building the output decreases, but the overall increase for the community still sums up to 21%.

Figure 41 illustrates the CIRE penetration comparison described above.

[14] As calculated using http://pvwatts.nrel.gov/

Figure 41: CIRE Penetration Comparison



In this study, the buildings are assumed to be new developments and the equipment on the rooftop can be placed in a way that facilitates installation of PV. However, in most cases actual measurements of the available unshaded roof area of the studied buildings have to be taken, especially if the community includes existing buildings.

8.5.2 Solar Thermal

Solar thermal systems can generate hot water to supply both distributed and district thermal systems, thereby reducing energy and emissions associated with heating. The integration of solar thermal also increases the differential pressure in the distribution network, which may enable turndown of distribution pumps at the CUP, which in turn saves further energy and emissions.

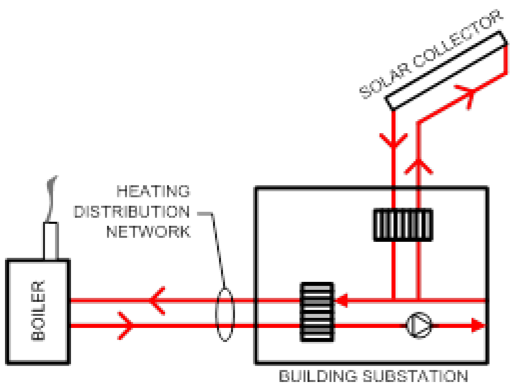
As discussed previously, district thermal systems free up roof space and leave more space for the installation of solar thermal and/or solar PV systems. District energy systems thereby increase the potential for integration of such technologies. Furthermore, the diversity of the loads within the district allows for larger solar thermal plants.

There are several configurations in which solar thermal systems can connect to a district energy system. These include but are not limited to the following:

- on the building side of the heat exchanger in the substation
- on the distribution side of the heat exchanger in the substation
    - on the supply distribution
    - on the return distribution

The advantage of connecting the solar collectors on the building side of the heat exchanger as illustrated in Figure 42 is that it allows a lower output temperature from the solar collector, which increases its efficiency. However, this connection results in increased return temperatures in the distribution network, which lowers the efficiency in systems using cogeneration, waste heat recovery or condensing boilers. In this study the heat source is assumed to be condensing boilers and connection to the distribution side is therefore more advantageous. It should also be noted that due to the variation in the output from the solar collectors a storage tank is often needed, especially in residential buildings.

Figure 42: Building Side Solar Thermal Connection



Conversely, by connecting a solar thermal system on the distribution side, the distribution network functions essentially as a large thermal storage tank and often no additional storage is needed within buildings (depending on the size of the district heating system, the diversity of the connecting loads and the scale of the solar collector output).

A solar thermal system can be connected to the distribution side on either the supply line, or the return line, as illustrated in Figure 43 and Figure 44.

Figure 43: Solar Thermal System Connection to Supply Line of Distribution Side

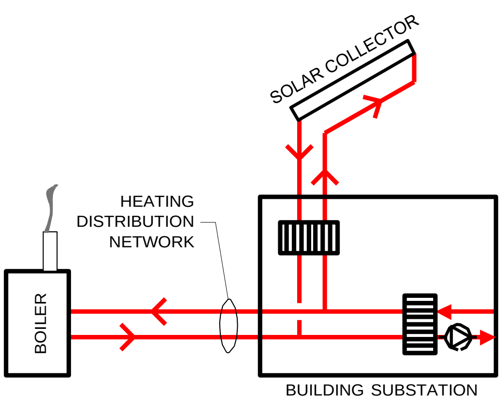
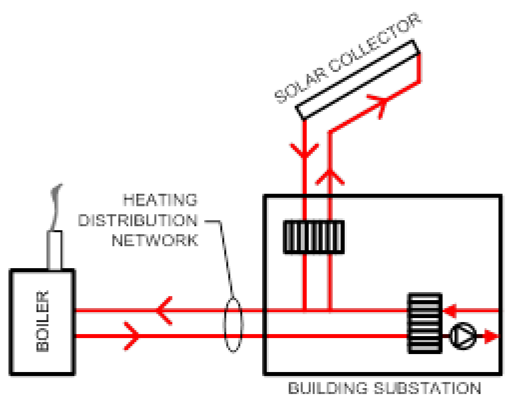


Figure 44: Solar Thermal System Connection to Return Line of Distribution Side



The optimal distribution side connection will depend on the type of base heat production in the system, as well as the temperature of the district energy system. A solar collector connected to the return line allows delivery of lower temperature, which increases overall efficiency. On the other hand, the boiler and heat recovery chiller efficiencies decrease with higher return temperature.

Low-temperature systems allow for connection to the supply side, while still maintaining a reasonably high efficiency in the solar collectors. When connecting to the supply pipe, it is therefore important to make sure that the heat exchangers in the substations are designed for the output temperature of the solar collectors.

Roof mounted solar collectors connected to the distribution side raise the questions about ownership and contracts. The most common solution is where the collectors are owned by the building owner, who trades the solar heat according to a net-metering contract with the district energy provider (in the same way as grid-connected solar PV).

However, there are examples in Germany where the district energy provider owns the solar collectors that are housed on privately owned buildings. If this ownership model is applied, there needs to be a contract defining the easement of the real estate, maintenance, liability for the building and equipment, as well as responsibility of deconstruction.

8.5.3 Renewable Fuels

Two of the value propositions of district thermal energy are increased fuel flexibility and the opportunity for real-time and competitive fuel purchasing. These are enabled by the centralization of the energy conversion function, which in turn is scaled up due to aggregation of loads. The resulting scale and single point of fuel use makes the purchasing and utilization of renewable fuels in district energy systems more feasible than at a building level.

Depending on policy, goals, and fuel availability, renewable fuels can be used to supplement, reduce, or entirely replace the use of fossil fuels such as natural gas. Two primary forms of renewable fuels are presented in the following subsections.

8.5.3.1 Biogas

Renewable biogas is generated through the anaerobic digestion of the organic portion of solid waste, manure, sewage, and plant material. Once upgraded (removal of carbon dioxide [CO_2] and trace gases), biogas can be used as a fuel source for generating thermal and electrical district energy. There are broadly two methods by which biogas can be used in district energy systems: direct biogas and directed biogas.

Direct biogas refers to the on- or off-site generation of biogas for use directly as a fuel source on-site.

Directed biogas, or pipeline biomethane[15], is biogas that meets pipeline-quality natural gas standards. Directed biogas is typically created at centralized locations such as wastewater treatment plants, large farms, and landfills and other solid waste sites. Due to the infrastructure expense and energy created and used, it is typically not practical to dedicate an individual pipeline from the digester to a project site. Biogas has a more sustainable impact when it is

[15] As defined by Article 5. Sections 95800 to 96023. Title 17. California Code of Regulations.

injected into an existing natural gas pipeline (as pipeline biomethane) that is connected to the district energy plant.

Given that district heating plants in urban settings will often be space-constrained, district heating providers are likely to find directed biogas to be a much more feasible option for biogas than direct biogas.

To pursue directed biogas fuel supply, the district thermal energy operator (or building 1 owner depending on the model utilized) will have to contract directly with an in- or out-of-state biogas-generating entity. Such a contract would have to ensure that all measurement and verification requirements are in place to ensure that the quantity and quality of the biogas injected into the network in fact offsets an equal amount of natural gas supplied by the network.

Directed biogas contracting may increase fuel costs for the district energy provider (or building 1 owner). One way to manage those additional costs is to pass the premium on to the other Flower Market buildings through a "green energy customer" program that would entitle customers to ownership of the associated Renewable Energy Certificates in an amount proportional to their source energy use.

8.5.3.2 Biomass

Biomass is plant or plant-based material that can be used directly as a source of thermal energy through a combustion process. Wood is the primary fuel used in the biomass energy industry, with agricultural and forestry waste being the most prevalent sources.

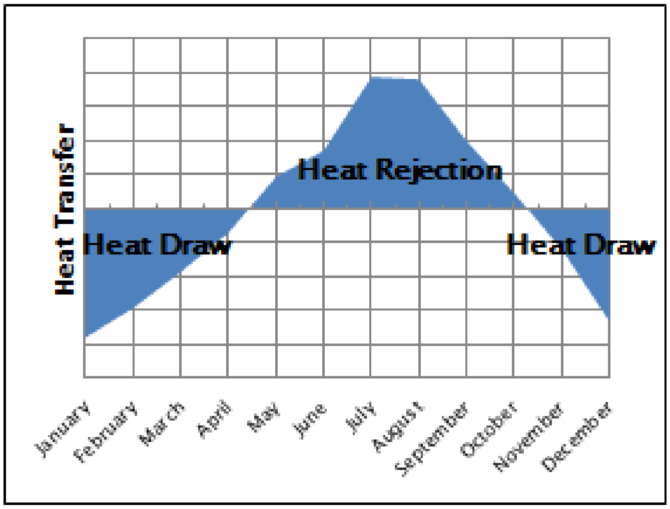
Similar to the anaerobic digestion and gas cleanup processes required to generate useable biogas, biomass also requires careful fuel preparation. This typically entails pelletization of wood to maximize surface area and subsequently maximize combustion efficiency. Unlike biogas, however, biomass cannot be used in lieu of natural gas directly in standard gas-fired boilers. The district thermal energy operator (or building 1 owner) will instead have to install biomass boilers or pursue burner retrofits in order to utilize biomass.

Unlike biogas, which can be injected into a grid at one point and be effectively consumed at the district energy plant, biomass requires physical transportation to the district energy site. This often requires additional loading, circulation, and, most importantly, storage space on-site, making it a challenging strategy to implement at existing district energy systems.

8.5.4 Ground and Water Source Thermal Exchange

Ground and/or water source heat exchange refers to the coupling of building primary heating and cooling systems with the ground or with a body of water to store and extract heat in the summer and winter respectively. A ground/water source heat exchange system therefore requires a seasonal balance in thermal loads as illustrated in Figure 45.

Figure 45: Example of Seasonal Thermal Load Balance

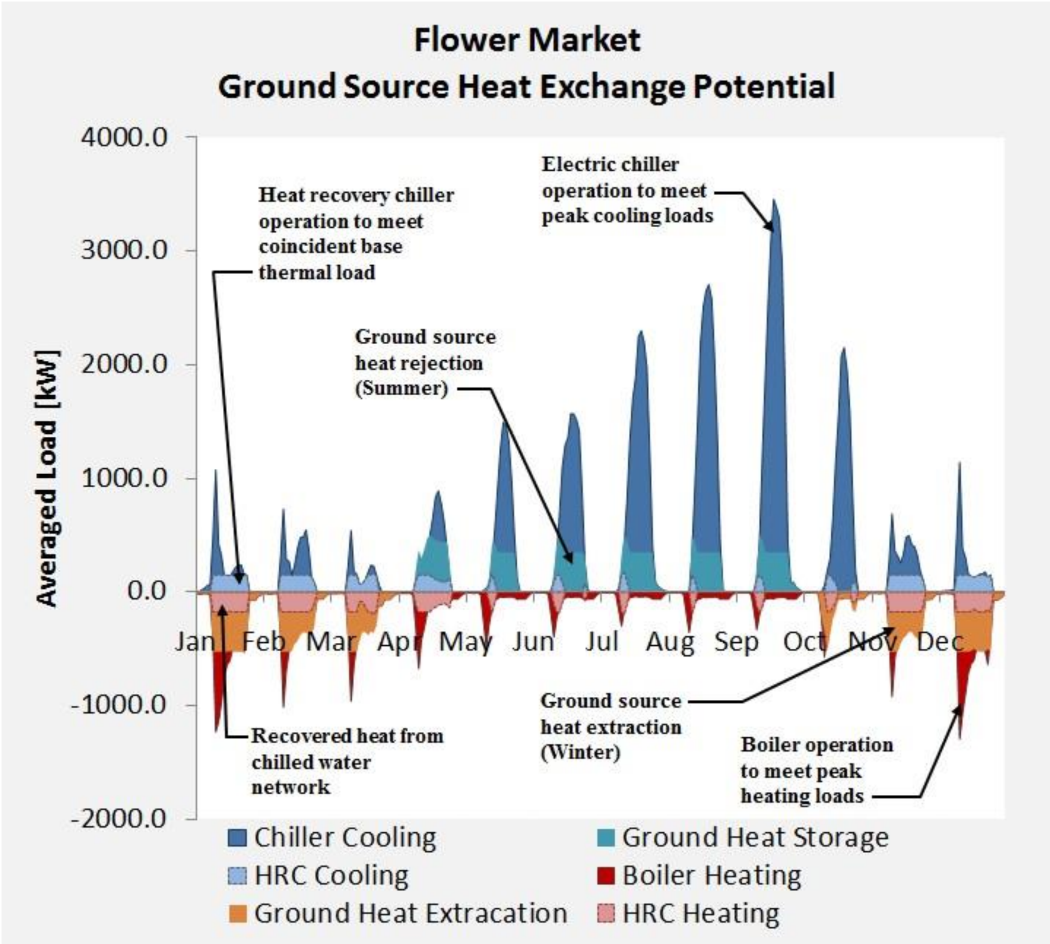


These systems are often spatially and cost prohibitive at the scale of a single building due to the large upfront costs and routing associated with the secondary system.

However, the feasibility of such systems can improve due to the benefit of scale associated with district thermal systems.

The indicative Flower Market area development for example, though not near a body of water, could benefit from a ground source heat exchange system. Such a system would be restricted in size by available land area, and optimized in size to balance seasonal heating and cooling loads. Since the selected technology includes heat recovery chillers, this optimization would also take the heat recovery chiller duty into account as illustrated by Figure 46.

Figure 46: Average Operation of Indicative Ground Source Heat Exchange at the Flower Market District



The DEF analysis suggests that such a ground source heat exchange system would result in further energy, resource, and carbon reductions[16] as summarized in Table 17.

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[16] Reported for the year 2030

Table 17: Estimated Community Energy Reduction Using a Ground Source Heat Exchange System

Change in Energy Use	**kWh**	**Therms**	**kbtu**
Cooling Energy Increase	237,200		810,100
Heating Energy Reduction		103,652	3,035,200
Pumping Energy Increase	14,500		49,600
Total Energy Reduction			2,175,500
Assumptions			
1. Ground source heat pump average annual COP = 5.0			
2. Ground source heat pump system pumping = 10% of total energy			

This estimated energy reduction resulting from the incorporation of a ground source heat exchange system translates into a 1.15 kbtu/ft^2/year EUI reduction for the indicative Flower Market community.

The 2 primary ground source heat exchange systems are as follows:

- vertical systems
- horizontal systems

Figure 47**: Vertical Ground Source Heat Exchange System**

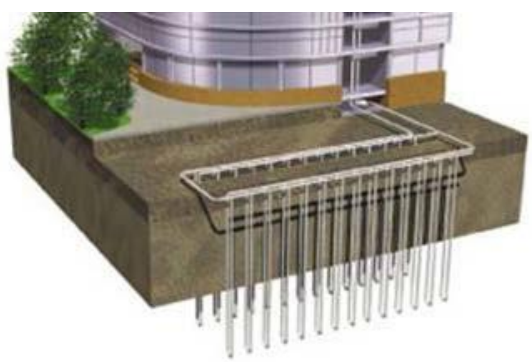
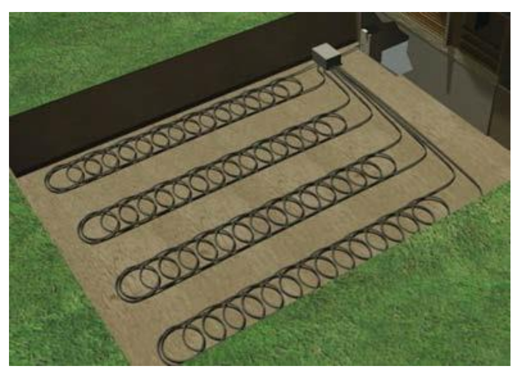


Figure 48**: Horizontal Ground Source Heat Exchange System**



Vertical systems require less land area, but are typically more cost prohibitive due to boring/drilling costs. Careful planning can mitigate some of these costs by coupling the ground source system boring/drilling works with the building foundation excavation/drilling works. Horizontal systems on the other hand are more cost effective, but require much larger land area, and are therefore less feasible in a dense urban environment.

The conceptual district thermal system serving the indicative Flower Market community could therefore benefit from a supplemental, appropriately sized vertical ground source heat exchange system. Such a system would not only achieve a greater CIRE penetration for the Flower Market community, but would also result in reductions in primary heating and cooling equipment capacity as described in Section 3.3.1, and, subsequently, freed up real estate as described in Section 10.4.

CHAPTER 9: Performance Implications

This section provides a comparison of the environmental and economic performance of the district thermal energy scheme against the baseline thermal scheme described in CHAPTER 7:

- Section 9.1 describes the capital cost estimate that was prepared for the baseline scheme and the district thermal energy scheme.
- Section 9.2 discusses the operational performance by comparing various metrics including energy, water, carbon, and O&M.
- Section 9.3 provides a life cycle cost analysis that compares the two schemes over a 25-year horizon

These costs, however, were not specifically allocated to any specific parties, such as building developers, owners, tenants, or district system providers, but rather as a collective. To further understand the individual business cases for connection, hosting, using, and/or operating the system would require another layer of assumptions around investment, ownership, and operations.

9.1 Capital Costs

Arup has a team of in-house certified cost engineers providing construction cost estimating and scheduling support services on a wide range of building and infrastructure projects. The capital cost estimates developed for this study were prepared by this team in coordination with the design team utilizing a true multidisciplinary approach.

The level of accuracy for the estimates were based on recommendations set forth by the Association for the Advancement of Cost Engineering International (AACEI), which were used to develop the estimate classification matrix in Table 18. The five levels are based on the level of completion of the design.

Table 18: Estimate Classification Matrix

Estimate Level	Estimate Description	Design Phase	Level of Design Completion	Methodology	Accuracy Range
5	Rough Order of Magnitude	Planning Schematic Design	0% to 5%	Parametric Models Capacity Factored Historical Costs	L: -20% to -50% H: +30% to +100%
4	Concept Feasibility	Planning Schematic Design	1% to 15%	Equipment Factored Parametric Models	L: -15% to -30% H: +20% to +50%
3	Budget Authorization	Planning Schematic Design Design Documents	10% to 40%	Unit Costs Assemblies	L: -10% to -20% H: +10% to +40%
2	Budget Control Estimate	Preliminary Design Engineering Design Documents Construction Documents	30% to 70%	Detailed Unit Cost with Forced Detailed Take-Off	L: -5% to -15% H: +5% to +30%
1	Bid	Detailed Design Engineering Constrution Documents	50% to 100%	Detailed Unit Costs Detailed Take-Off Production Based Estimate	L: -2% to -5% H: +3% to +15%

These estimates are classified as Class 4 Concept Feasibility with the primary characteristic being the conceptual level of design definition. We have provided a range of costs with the level of accuracy of the most likely cost being between -5% and +25%. The pricing used is based on an internal database of benchmarked projects and input from local bay area contractors as well and mechanical equipment and material suppliers.

The capital costs include the following items:

- construction price, including
  - contractor direct costs
  - contractor indirect costs/general conditions
  - contractor overhead and profit
- soft costs, including
  - preliminary engineering
  - final design
  - project management for design and construction
  - construction administration and management
  - professional liability and other non-construction insurance
  - fees for legal, permits, reviews, surveys, testing, inspection and start up
- design and construction contingency
- owner contingency/management reserve

Figure 49 provides a summary of the two options, where the three cost categories are as follows:

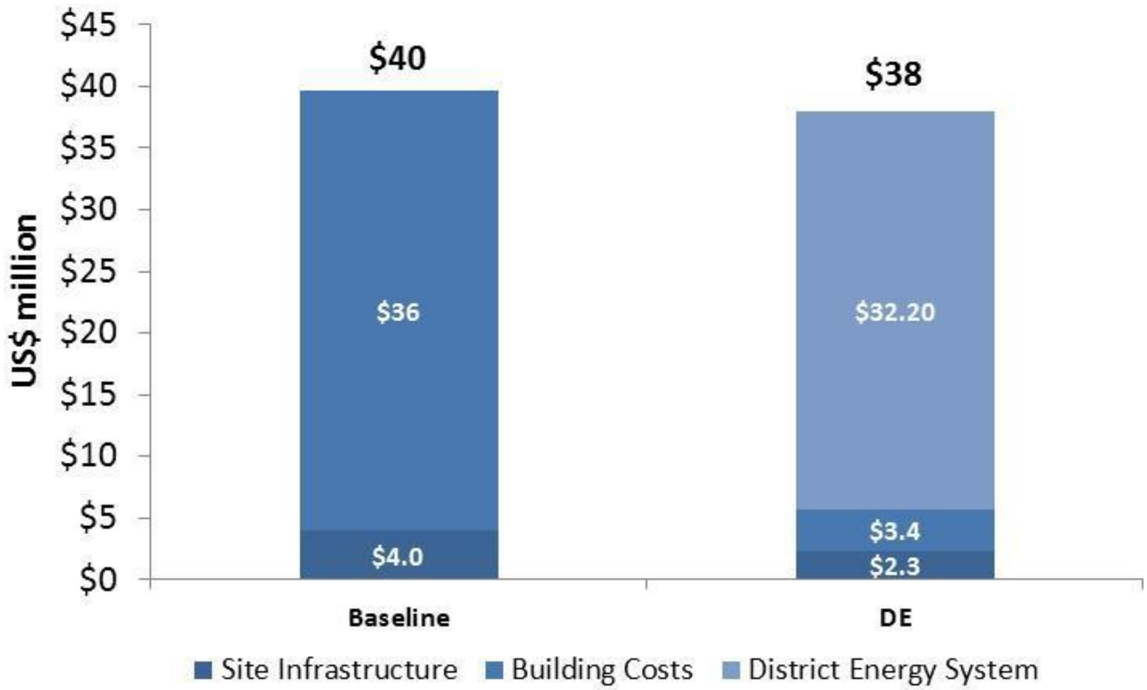
- site infrastructure – electrical and gas connections and equipment
- building costs – all heating and cooling equipment on building level (only building substations in the district thermal strategy), as well as the value of building space required for the heating and cooling equipment
- district energy system – central plant and distribution network

The result shows lower capital expenditure for the district thermal system compared to the baseline. This is explained by the reduced capacity of heating and cooling equipment in the district thermal strategy (resulting in lower mechanical equipment first costs and less use of valuable building space), as well as the small scale of the studied district (resulting in low costs for the distribution piping).

District energy systems free up valuable building space (which is further discussed in section 10.4). The value of the space required for heating and cooling equipment for each scenario is included in the capital comparison as a cost. These costs are estimated to $7.0m for the baseline and $3.2m for the district energy scenario.

Further breakdown of the cost estimation is presented in APPENDIX B.

Figure 49: CapEx Comparison



9.2 Operating Costs

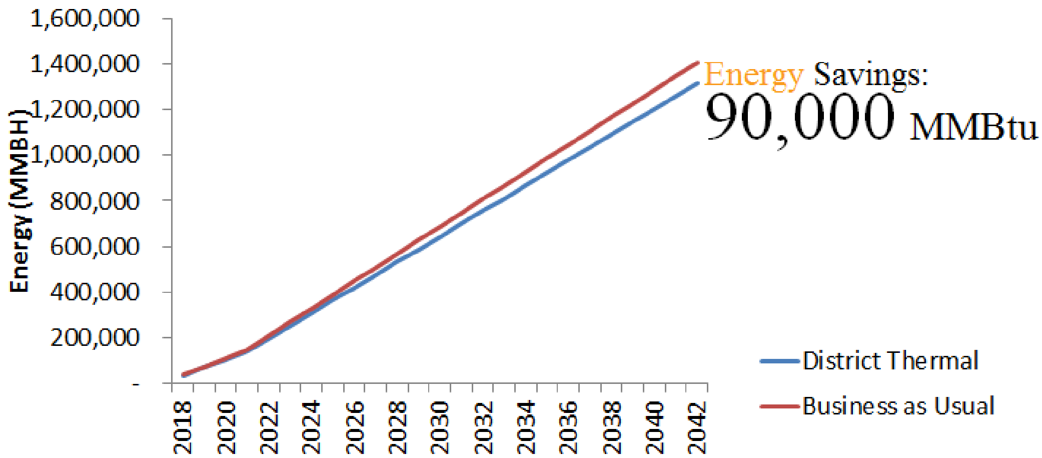
The economic value proposition of a district thermal system is generally realized if the operating cost reductions outweigh the capital cost premium over the life of the system. The following sections explore each of the operating cost categories that collectively make up the overall operating expense of the system and specifically call out the difference in resource consumption and manpower need for operation. Section 9.3 address the expected cost of these resources over time, including escalation pricing.

9.2.1 Energy

The community energy supply analysis was carried out using the DEF tool developed by Arup. The analysis estimates that the district thermal system will reduce the total energy consumption of the community by an average of 8,300 MMBtu annually compared to the baseline distributed thermal energy system. This represents an approximate Energy Utilization Intensity (EUI) reduction of 4 kbtu/ft^2/year.

Figure 50 shows the cumulative energy (electricity and natural gas) consumption for the baseline and the district thermal energy system over the 25-year study horizon.

Figure 50: Cumulative Energy Consumption Comparison



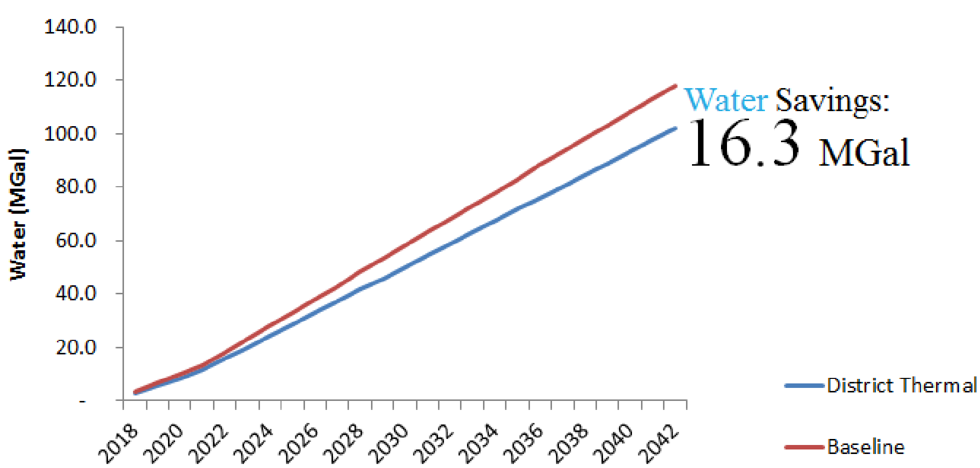
Section 9.3 describes the conversion of energy to energy cost.

9.2.2 Water

In addition to the energy implications of distributed and district thermal energy schemes, the DEF tool was used to calculate the resulting process water usage under each scenario. The analysis estimates that the district thermal system will reduce the total process water consumption of the community by an average of 5 MGal annually compared to the baseline distributed thermal energy system, or a 2.6 gal/ft²/year reduction for the community.

Figure 51 shows the cumulative process water consumption for the baseline and the district thermal energy system over the 25-year study horizon.

Figure 51: Cumulative Water Consumption Comparison



Section 9.3 describes the conversion of water to the cost of water.

9.2.3 Operations and Maintenance

Buildings in the over-100,000ft² range typically employ full and part time staff to carry out O&M tasks. These tasks range from building engineering, minor repairs, and security, to janitorial, loading dock operation, and tenant services. This staff is often supplemented with service contracts for specialty equipment such as primary heating and cooling equipment, all of which set a building O&M budget.

Though often overlooked, the reduction in O&M staff and maintenance contracts for primary heating and cooling systems resulting from a shift to district thermal systems is actually one of the key value propositions for centralization, often more so than energy cost reductions. Engineering crews for multiple thousand square foot buildings with on-site chiller and boiler plants tend to be larger than crews for similar sized buildings connected to district thermal energy systems. This is due to the less extensive O&M regime required by building interconnections (essentially heat exchangers) compared to on-site generation plants.

Given the indicative nature of the Flower Market development, assumptions were made to capture this cost reduction as summarized in Table 19. Assumptions related to the escalation of staff costs can be found in Section 9.3.

Table 19: Flower Market Development Primary Heating and Cooling Equipment O&M Assumptions

Operations	**Baseline FTEs**			**District Energy FTEs**		
Shift	Day	Evening	Night	Day	Evening	Night
Control room	3.00	1.50	1.50	1.50	1.00	0.25
Daytime support	3.00			1.50		
Total	6.00	1.50	1.50	3.00	1.00	0.25
Maintenance	**Baseline FTEs**			**District Energy FTEs**		
Distribution	-			1		
Boilers/Heating	1.00			0.50		
Chiller/Cooling Towers	1.00			0.50		
Controls, Aux, Misc.	-			0.25		
Total	2.00			2.25		
O&M Cost	**Baseline Costs**			**District Energy Costs**		
Labor cost	120,000	US$/FTE/year		120,000	US$/FTE/year	
Total FTEs	11.00	FTEs/year		6.50	FTEs/year	
Total salary cost	**1,320,000**	**US$/year**		**780,000**	**US$/year**	

Though the O&M costs in Table 19 are summarized as totals, they will be incurred fractionally in each of the 6 indicative buildings. Therefore, Table 19 reflects the aggregated cost of O&M for the entire community, rather than for any 1 building owner/manager. With that view and the assumptions made, it is clear that centralization delivers an aggregated value for the community as well.

Figure 52 and Figure 53 illustrate the distribution of these O&M costs within the community buildings under the baseline (distributed) and the district energy schemes respectively.

Figure 52: Primary Heating and Cooling Equipment O&M FTEs and Costs: Distributed Thermal Energy (Baseline)

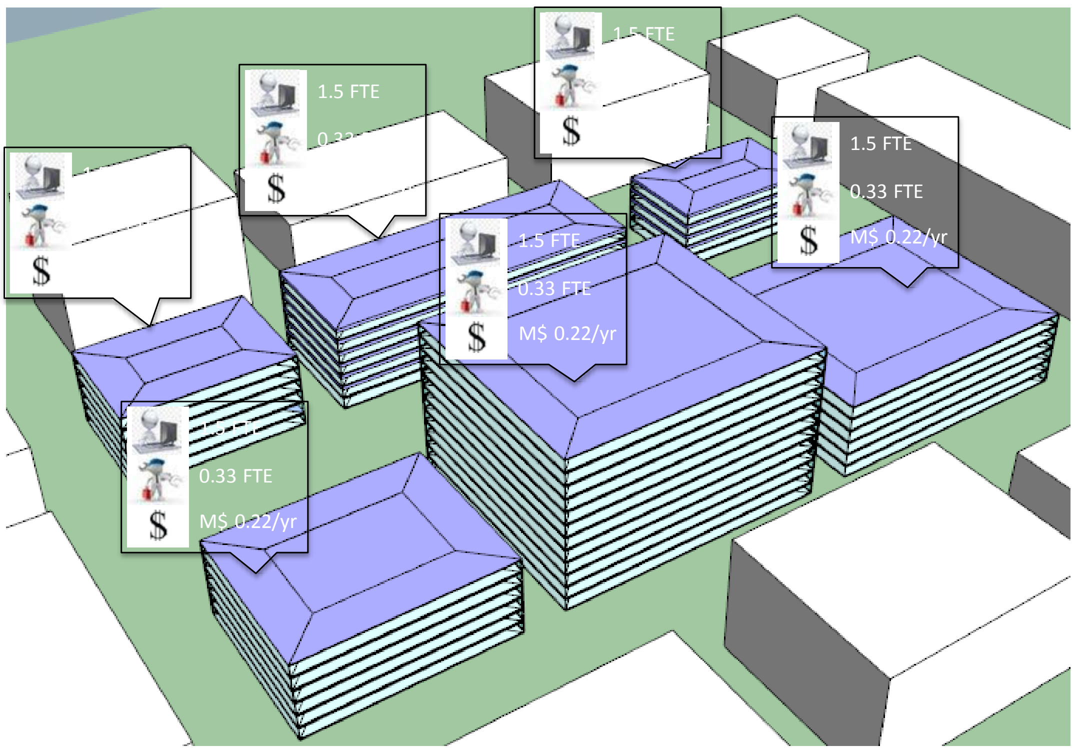


Figure 53: Primary heating and cooling equipment O&M FTEs and Costs: District Thermal Energy

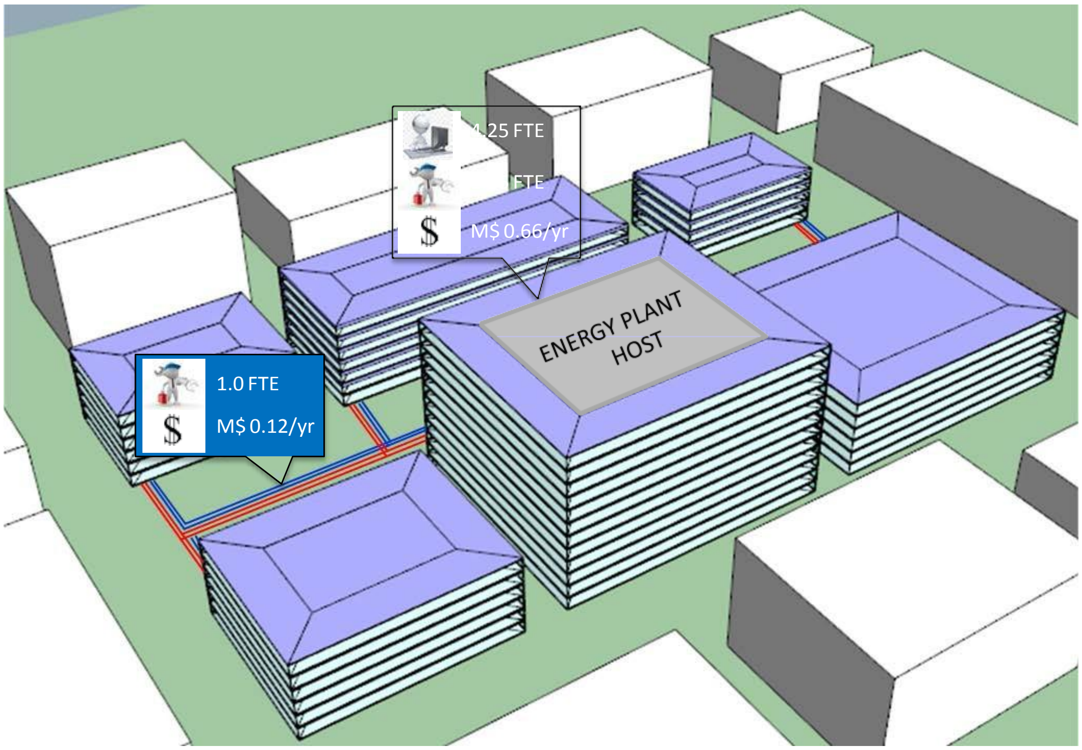


Figure 53, together with Table 19, shows that the building 1 (CUP) owner or district thermal energy operator (depending on the model used) incurs a much larger O&M cost in the district energy scenario than in the baseline. To capture the O&M cost reduction value for the community while also making a viable business case for themselves, the building 1 owner or district thermal energy operator will therefore have to set a thermal energy sale rate that is financially beneficial for the community and encourages connecting to the system, while also balancing their disproportionate O&M cost burden.

The assessment in this study is carried out with a view of the community as a whole, and the business case is therefore communicated using the life cycle cost analysis for the entire system as summarized in Section 9.3 . For cities and districts looking to understand the business case from the stand-point of the operator, a thermal sale rate analysis that considers the revenues from thermal energy sales against the costs of fuel, capital, and O&M would be more appropriate. Eventually, the perspective of the district system operator and building owner/developer needs to be considered, as their rent, taxes, and/or utility bills are likely to be impacted.

9.2.4 Carbon

The utilization of purchased electricity and on-site natural gas combustion result in carbon emissions under each of the baseline and district thermal systems. These emissions were calculated using the grid emission factor assumptions summarized in Table 20.

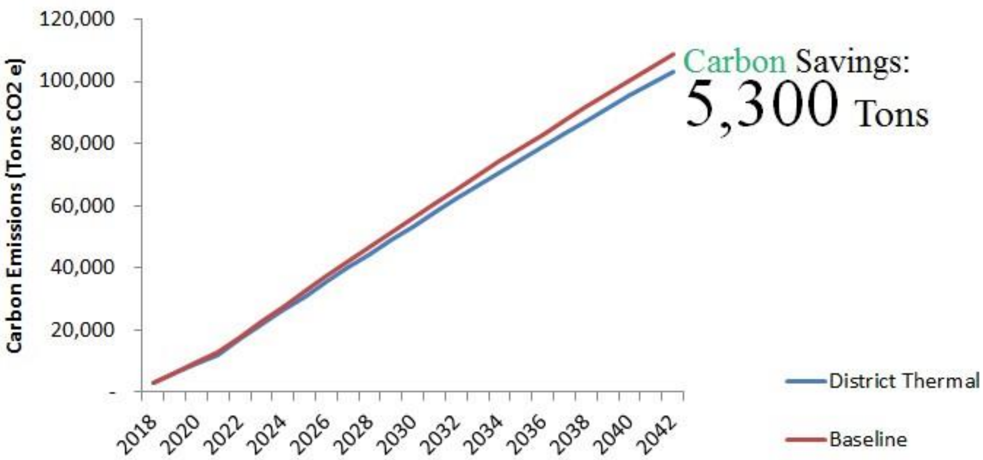
Table 20: Emission Factor Assumptions

Calendar Year	Purchased Electricity	On-Site Natural Gas Combustion
	lb/kWh	lb/Therm
2018	0.70	11.71
2019	0.69	11.71
2020	0.68	11.71
2021	0.68	11.71
2022	0.67	11.71
2023	0.66	11.71
2024	0.66	11.71
2025	0.65	11.71
2026	0.64	11.71
2027	0.64	11.71
2028	0.63	11.71
2029	0.63	11.71
2030	0.62	11.71
2031	0.61	11.71
2032	0.61	11.71
2033	0.60	11.71
2034	0.59	11.71
2035	0.59	11.71
2036	0.58	11.71
2037	0.58	11.71
2038	0.57	11.71
2039	0.57	11.71
2040	0.56	11.71
2041	0.55	11.71
2042	0.55	11.71

The emissions analysis suggests that an estimated 230 tons of CO_2e emissions are avoided annually under the district system scheme.

Figure 54 shows the resulting cumulative carbon emissions for the baseline and district thermal systems respectively.

Figure 54: Cumulative Emissions Comparison



Section 9.3 describes the conversion of carbon to the cost of carbon.

9.3 Life Cycle Cost Analysis

This section presents the results from the life cycle cost analysis of the district thermal and baseline strategies. The analysis represents the lifetime costs of the studied thermal systems, excluding the in-building thermal distribution systems, which are assumed to be equal for the two scenarios. A lifetime period of 25 years was applied in the analysis, because it represents average lifetime of equipment in thermal systems. Table 21 and Table 22 summarize the assumptions for development soft costs and escalation factors used in the analysis.

Table 21: Development Soft Cost Assumptions

Cost Category	Percentage	Description
Indirect Costs	26.5	% of Direct Costs
Soft Costs and Design & Contingency	42.8	% of Construction Costs
Owner Contingency	10.0	% of Construction & Design Costs

Table 22: Escalation Factors

Costs	Escalation Factor (%)
CPI	3.1
Labor	4.0
CapEx	3.5
Natural gas	2.1
Electricity	5.0

The comparison of operational expenditure is presented in Figure 55. The greatest savings are due to reduction in operation and maintenance cost, as discussed in Section 9.2.3. Savings in energy, water, and carbon emissions correspond to the reductions presented in Section 9.2.

Figure 55: OpEx Comparison

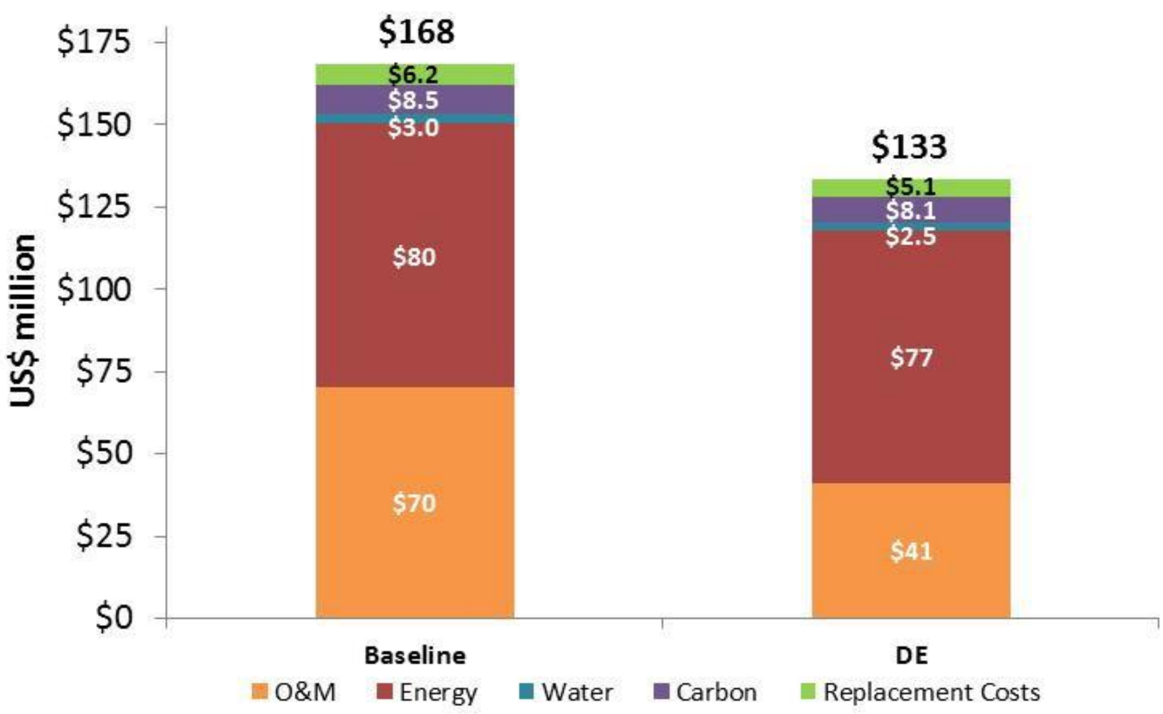


Figure 56 illustrates the total cost of ownership and summarizes the financial benefit of the district thermal system. It is possible that the district thermal system would be developed and owned by a third party, in which case the building developers' collective capital expenditure related to primary heating and cooling equipment would decrease from $35.7m to $3.4m. For more detail, see Figure 49 and APPENDIX B.

Figure 56: Total Cost of Ownership

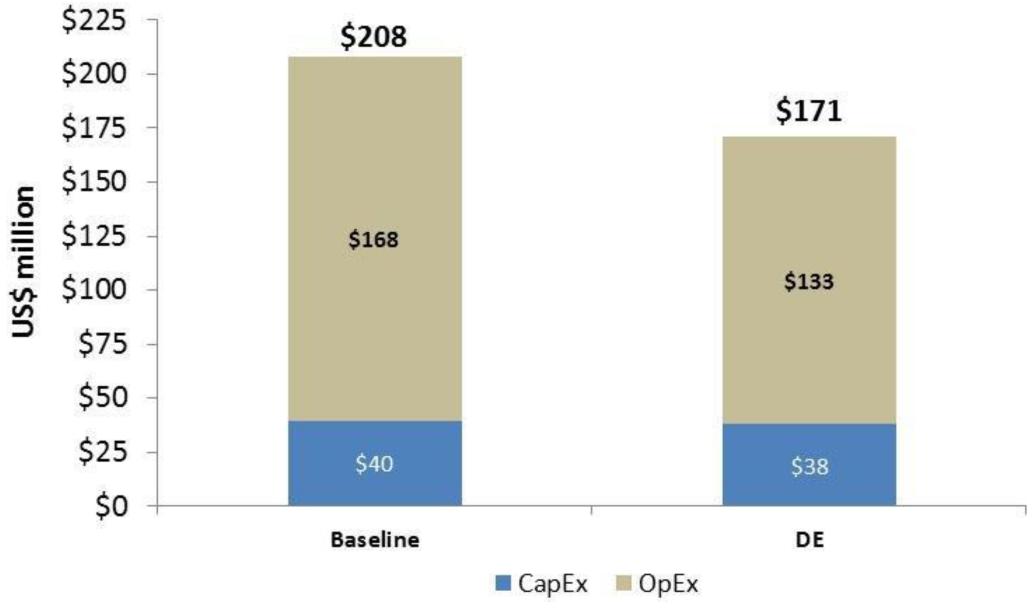
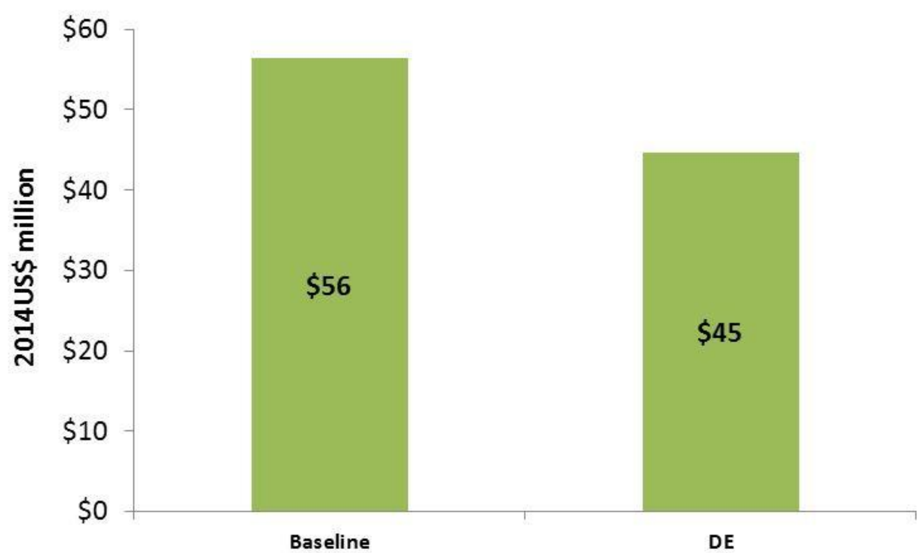


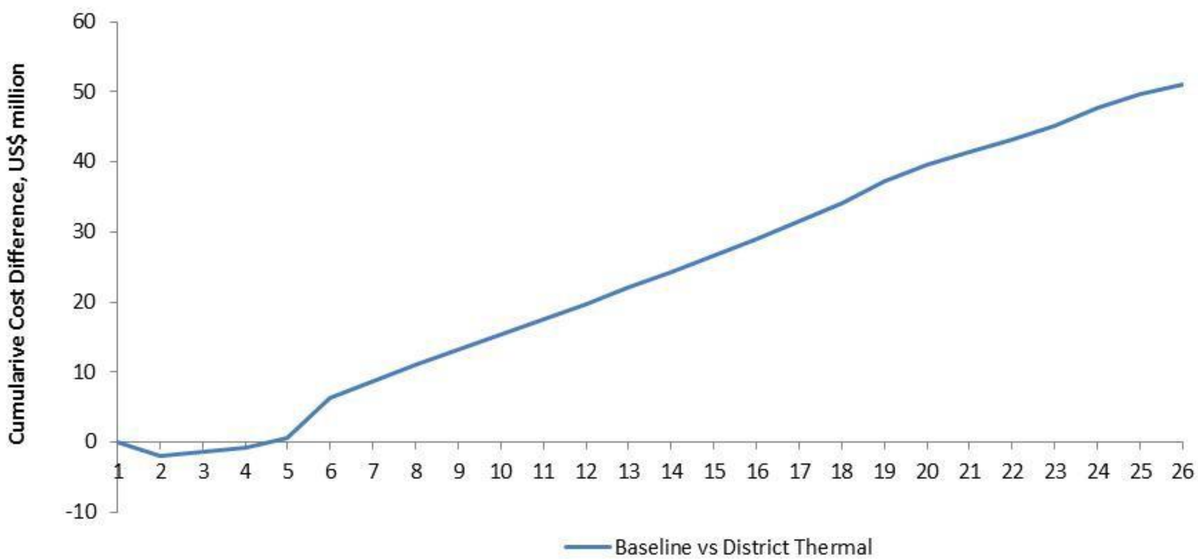
Figure 57 shows net present cost savings of $13m with a 10% discount rate.

Figure 57: Net Present Cost



The cumulative savings of the district thermal system relative to the baseline is summarized in Figure 58 and shows that the discounted payback time is approximately 4.5 years. The primary reason for not having an instantaneous payback (as the district system capital expense is less than the baseline) is due to the timing of construction and insulation, with the district system requiring more upfront capital and baseline requiring equipment as buildings are developed.

Figure 58: Cumulative Savings for District Thermal Relative to Baseline



CHAPTER 10: Discussion

10.1 Creating Synergies

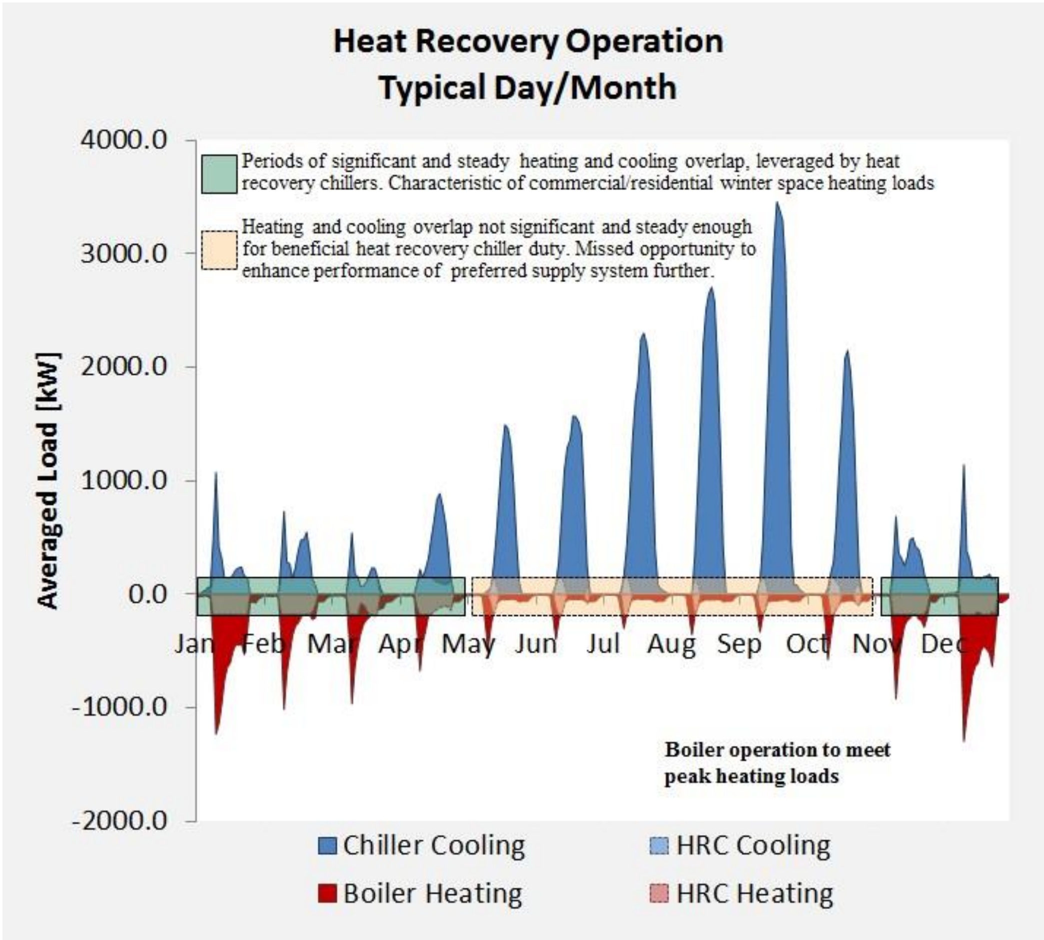
The district thermal energy assessment documented in this report is built from a hypothetical land use and phasing program. This exercise of optimizing a district thermal energy system for a fixed program or community is the standard way in which developments, business improvement districts, campuses, and cities approach district energy for new developments — by optimizing supply for a fixed demand.17

However, smart cities and districts can do better by optimizing the demand and supply side of the equation simultaneously. Through smart zoning and development informed by iterative district energy performance analysis, the thermal (and electrical) demands of a community can be manipulated to enhance the performance of the supply-side systems.

In the case of the indicative San Francisco Flower Market area and the selected technology (central heating and cooling with heat recovery chillers), Figure 28 summarizes the average day per month heat recovery potential. It illustrates that the chosen technology was preferred despite the limited year-round coincident simultaneous heating and cooling demand. The foregone heat recovery potential is illustrated in Figure 59 and is a direct function of the zoning and land use program assumed.

[17] Continuous demand-side management becomes a major part of the approach once the district system is built or when a new district system is proposed for existing buildings.

Figure 59: Supply System Performance Limitation Due to Land Use Mix



The heat recovery component of the selected technology is central to the energy, water, and carbon reductions summarized in Section 9.2, yet Figure 59 clearly indicates that this recovery is significant only between November and April. This suggests that the manipulation of demands through smart zoning should target the addition of land uses with steady, year-round heat demands to the existing mix. Such land uses could include but are not limited to the following:

- in-patient hospitals
- commercial laundry facilities
- gymnasiums with swimming pool, shower, and laundry amenities
- industrial land uses such as breweries

Though district energy essentially aggregates and "flattens" the concurrent load of a community to an extent, the addition of a steady, year-round, heat-demanding land use would enhance this effect in this case.

An indicative example of the application of smart zoning informed by iterative district energy performance was carried out for the Flower Market development. It was assumed that a commercial laundry facility with a year-round 500 kbtu/h heating demand could be added to the original Flower Market program as a way to enable greater heat recovery potential.

The results of this indicative exercise are illustrated by Figure 60 and Figure 61. The improvement in heat recovery chiller duty is immediately evident, which further improves the energy, water, and carbon performance of the district thermal system.

Figure 60: District System Performance: Linear Planning Approach

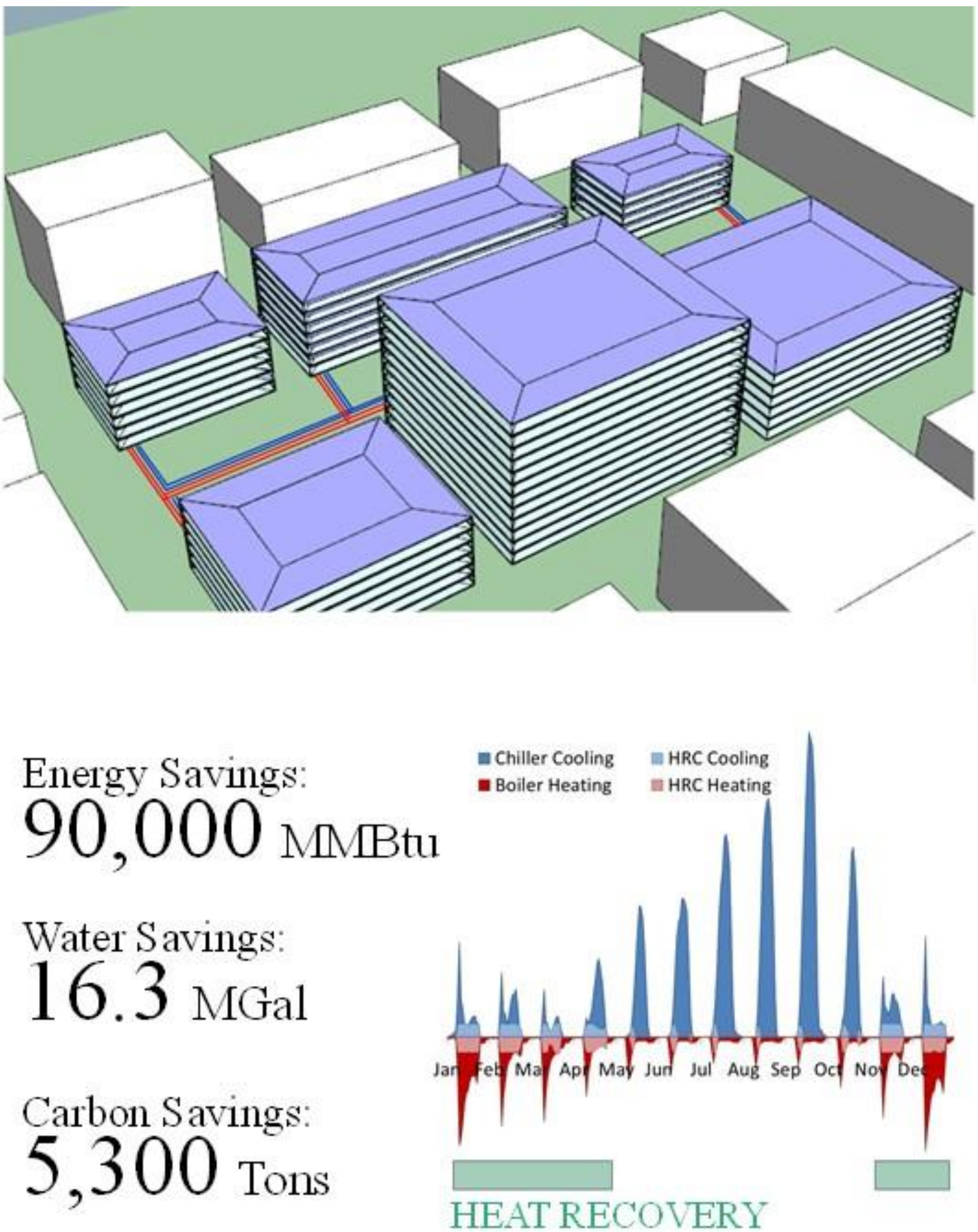
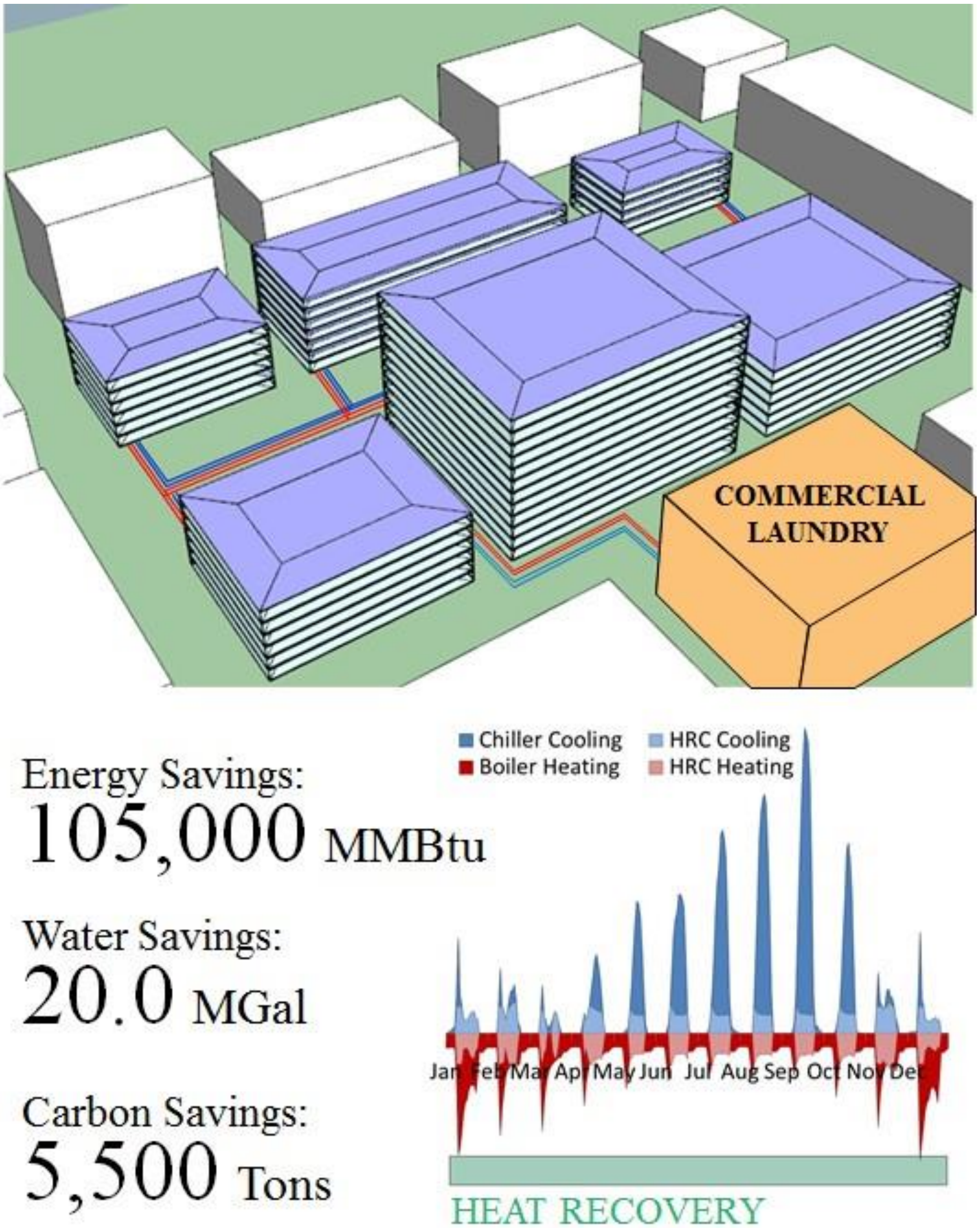


Figure 61: District System Performance: Iterative Planning Approach



This example is true in San Francisco given the year-round mild climate, in which a low-temperature system with heat recovery was the preferred system to begin with. Cities and districts looking to perform a similar exercise should do so with a climate-appropriate response. For example, a city with long and extreme winters may find that the addition of a constant, year-round cooling demanding land-use such as a data center is the most appropriate smart zoning response.

10.2 Leveraging Local Resources

Locally available resources such as waste heat, groundwater, and dormant or standby infrastructure that could possibly be multipurposed can further improve the efficiency of a district thermal system and/or make it more cost effective.

For example, one of the benefits of a low-temperature district heating system mentioned in Section 1.4 was the fact that it allows capture and reuse of locally available waste heat sources. Potential sources of waste heat in typical urban environment include but are not limited to the following:

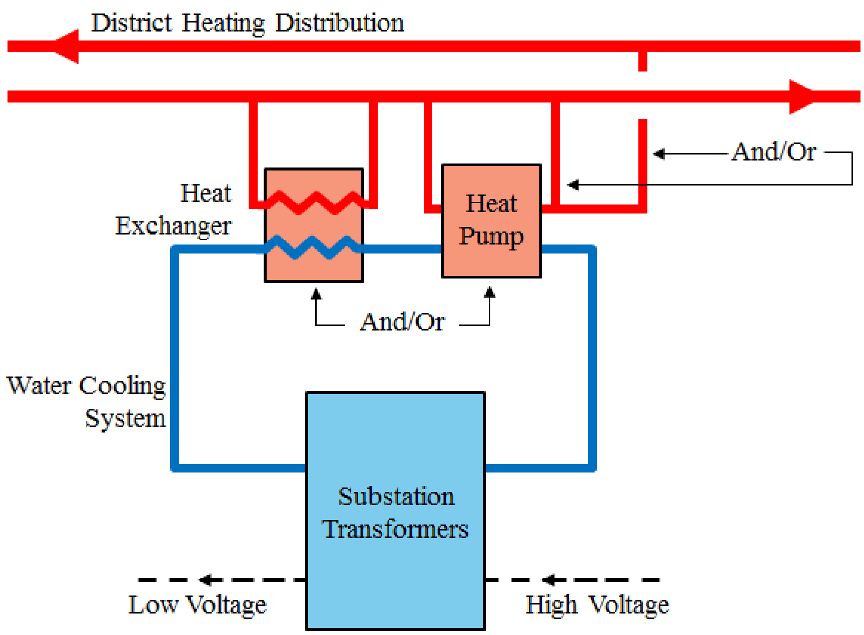
- electrical substations
- data centers
- industrial processes such as breweries
- sewer mains
- light and medium rail traction power dissipation stations

It is therefore a worthwhile exercise to map out key potential waste heat sources within and around a development for which a low-temperature district thermal energy system is being considered. This is a recommended next step for the Flower Market development. An example of such an exercise is illustrated by for the South Lake Union area of Seattle, Washington.

Figure 62: Potential Waste Heat Source Mapping in South Lake Union, Seattle, Washington

The capture and use of heat from urban sources would entail the use of distributed heat pump stations. These would be located at the waste heat source and would connect to the district thermal distribution system. An example of such an interconnection is illustrated in Figure 63 for an electrical substation tie-in and would be similar for a tie in to the other sources of waste heat listed above.

Figure 63: Substation Waste Heat Capture Configuration



Groundwater represents another example of a potential local resource that could be leveraged as part of a district thermal energy system. Cities or districts that experience groundwater surges and/or have to actively capture and dispose of groundwater could instead capture and divert groundwater to a district thermal energy CUP, where it could be treated and used as process water in lieu of virgin potable water. Process water uses could include cooling tower make-up water and boiler feed-water and blow-down water.

In San Francisco, the Bay Area Rapid Transit (BART) currently actively pumps groundwater out of the Powell Street station to protect it from water damage due to surging groundwater.[18] Groundwater recovery could therefore be an attractive strategy for the SoMa district as a way to reduce potable water consumption associated with a new or existing district thermal energy system.

10.3 Potential Interconnection with Existing District Thermal System

As described in the CIRE Task 3b report, NRG owns and operates a steam-based district thermal system in San Francisco. This system has some excess generation capacity with plans to grow further. It is also geographically situated near enough to the SoMa district to raise the question of whether or not some form of interconnection between systems is feasible.

[18] San Francisco's Clean Little Secret.
http://foundsf.org/index.php?title=San_Francisco%27s_Clean_Little_Secret

Given the preference for low temperature hot water, the interconnection between the proposed new district thermal system and the existing steam district thermal system would have to be limited to one-way generation only. This essentially means the following:

- Heat generated by the existing system can be used by the new system, and not the other way around.
- The two systems will have to maintain unique distribution systems (pipes).
- A substation allowing heat transfer (heat exchangers) from the steam system to the low temperature hot water system would have to be constructed at the interconnection.

Though this may seem to restrict compatibility, it offers a useful tool to help with the challenges of phasing a district thermal energy system. These challenges include the large capital costs associated with building a CUP and the low heat demands during the early years of operation due to a limited number of connected buildings.

The existing system could alleviate these challenges by limiting the initial system construction to the distribution and building substations only, and allowing a future CUP addition. This would reduce initial construction costs while also allowing the future hot water CUP to operate optimally once it is phased in to serve a significant or "anchor" demand. In the interim years, heat for the new district system would be generated and transferred by the existing district system, which already serves a significant heat demand.

10.4 Spatial and Social Benefits

In addition to the life-cycle cost benefits explored in the previous section, building owners in the Flower Market community will find that their buildings achieve improved net-to-gross area performance. Enabled by the centralization of primary heating and cooling equipment from individual buildings to a district thermal system, this essentially increases the amount of revenue making building area that owners can lease out.

Depending on the specific system chosen and its configuration within each building, owners may realize the "freeing up" of some or all of the following spaces:

- basement or back of house spaces normally allocated for chiller and or boiler rooms
- mechanical penthouse space normally allocated for chiller and boiler rooms
- yard, building set-back-well, or rooftop space normally allocated for cooling towers or dry fluid coolers
- fewer building exterior penetrations and louvers due to the elimination of boiler flues, chiller room vent lines, combustion air louvers, etc.

Figure 64 and Figure 65 illustrate the above described impacts of centralization for a typical urban commercial buildings in San Francisco between 100,000 and 350,000 ft^2.

Figure 64: Indicative Comparison for Distributed and District Cooling Building Plant Space

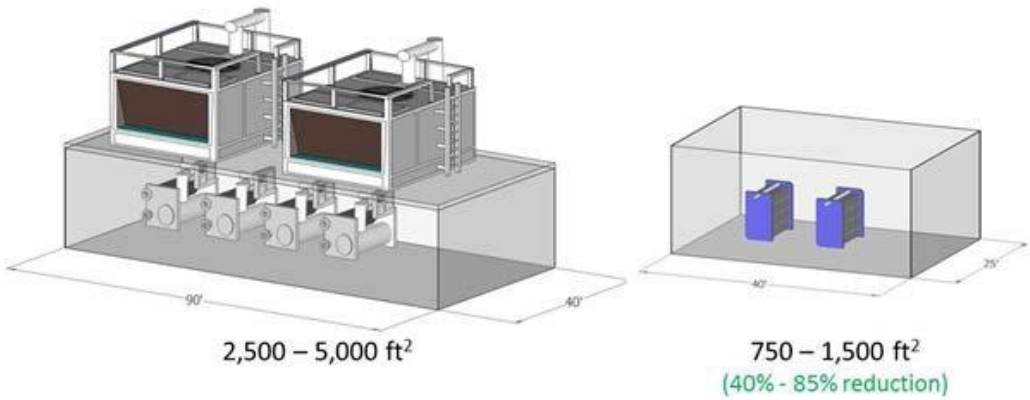
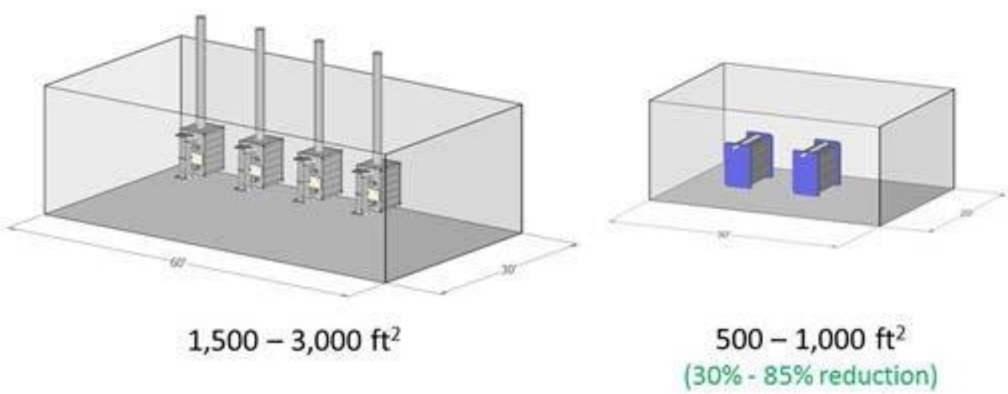


Figure 65: Indicative Comparison for Distributed and District Heating Building Plant Space



The above land use and programming implications may instead also enable the creation of Privately Owned Public Open Spaces (POPOS) embedded in the private urban environment. Such spaces are heavily utilized by the urban population as lunch break destinations, collaboration and meeting spaces, and spaces for respite. District thermal energy has the potential to unlock such spaces in the urban environment, as well as create unique private amenities for building owners.

Further reading about the benefits of POPOS as well as guides to San Francisco POPOS can be found on the San Francisco Planning Department website[19], and the SPUR website.[20]

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[19] "Privately-Owned Public Open Space and Public Art," City & County of San Francisco Planning Department, last modified October 6, 2013, http://www.sf-planning.org/index.aspx?page=3339#downtown_plan.

[20] "A Guide to San Francisco's Privately-Owned Public Open Spaces: Secrets of San Francisco." SPUR.

Figure 66: A SPUR guide to San Francisco POPOS (Credit Spur)

Figure 67 shows an example alternate layout for building 4 of the indicative Flower Market community. Such illustrations can send a powerful and engaging message to stakeholders during planning phases, especially when compared to renderings such as **Figure 27**.

Figure 67: Potential Rooftop Configuration for Building 4 Connected to a District Thermal Energy System

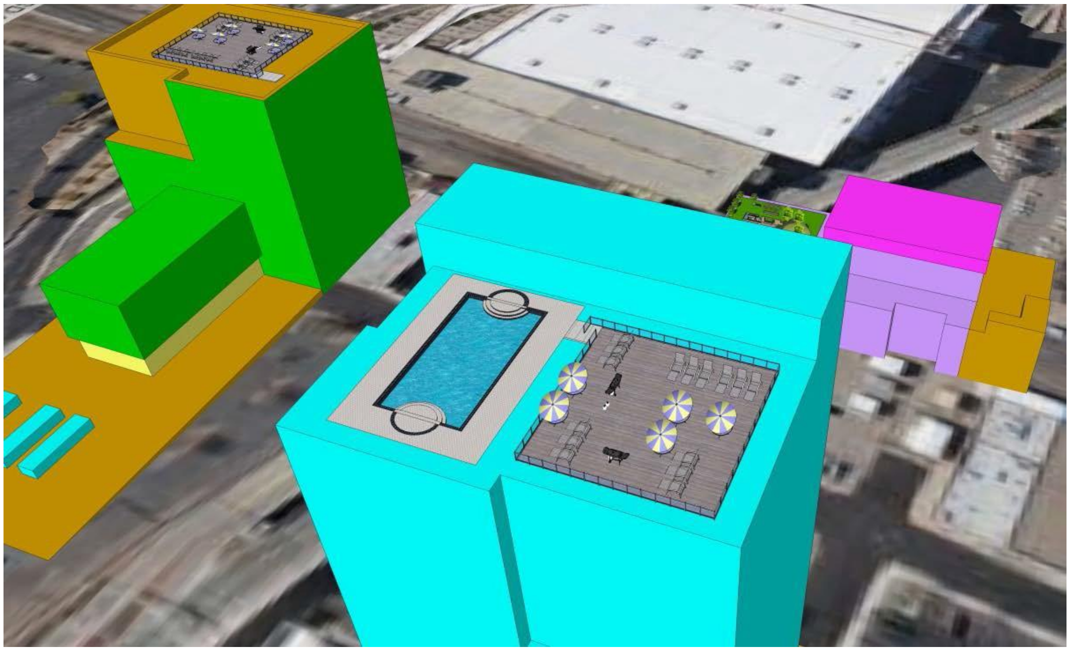
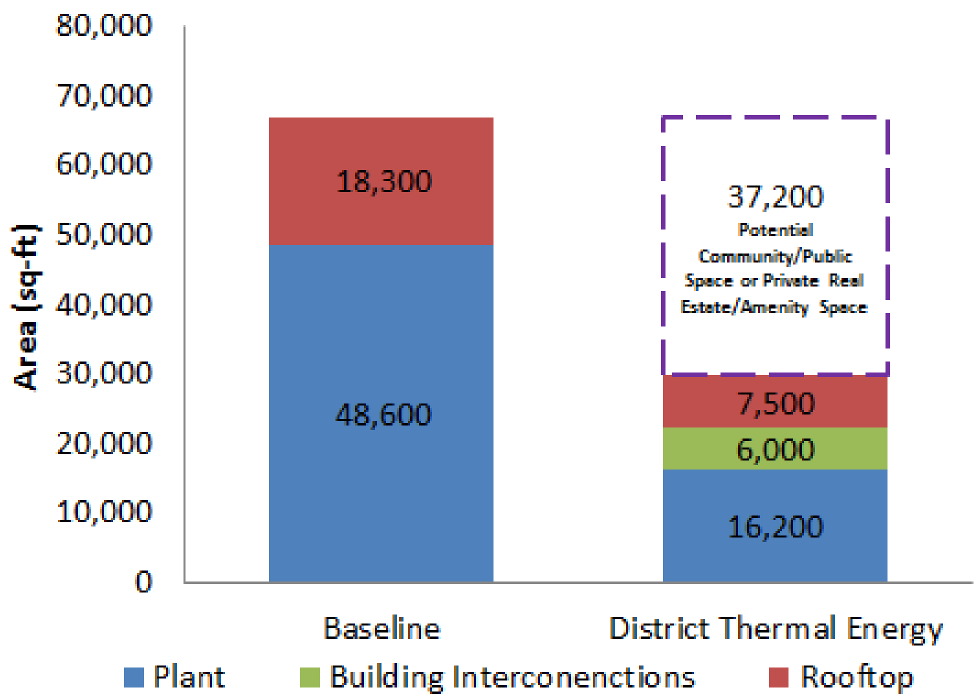


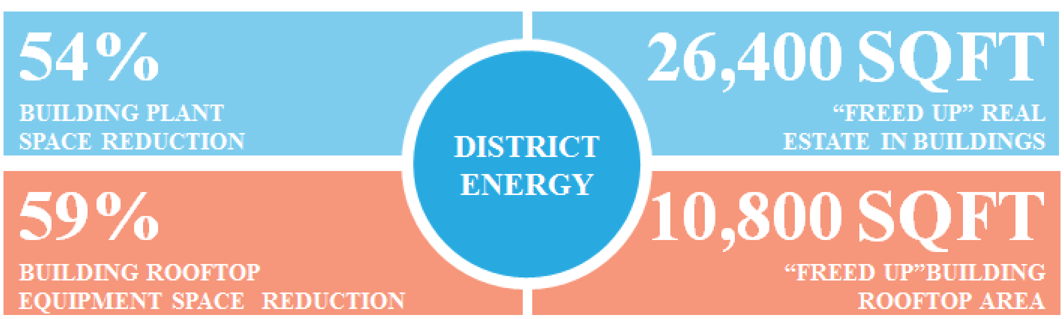
Table 23 and **Figure 68** summarize the above described spatial impacts of centralization for the conceptual district thermal energy scheme developed for the indicative Flower Market community.

Table 23: Primary Heating and Cooling Equipment Spatial Requirement Summary

	Plant (ft^2)	Building Interconnections (ft^2)	Rooftop (ft^2)	Total (ft^2)
Baseline	48,600	0	18,300	66,900
District Thermal Energy	16,200	6,000	7,500	29,700
Reduction	32,400	-6,000	10,800	37,200

Figure 68: District Thermal Energy Spatial Impact Summary



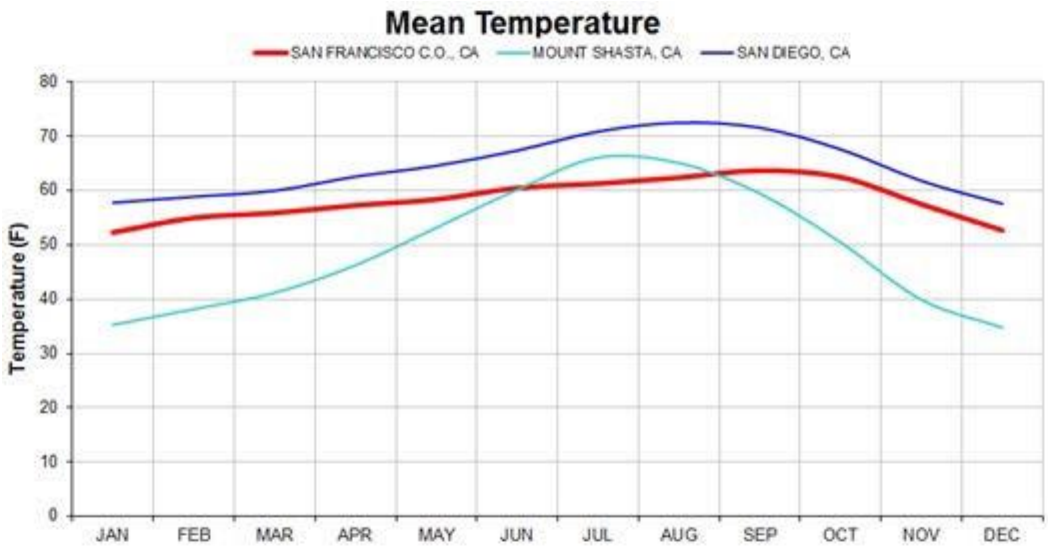


10.5 Replication across California

The approach for assessing a district thermal energy system developed in the smart growth report was applied and documented in this report for an indicative district in San Francisco. Together, the two documents therefore provide a guide to other cities and districts across California to carry out similar assessments.

It is important to note the aspects of this study that are unique to San Francisco, such as the year-round mild climate, and perhaps the planned major infrastructure projects that are spurring development and up-zoning. These parameters led to the subsequent development densities and configuration, and the technology filtering results documented in this report. These conclusions could vary significantly in other parts or California. Cities and districts exploring district thermal energy systems should therefore use the smart growth document as a guide, but should use this report only as an application of that guide.

Figure 69: Mean Temperature Comparison for Three California Cities



The following parameters may vary between cities and regions within California and should be considered as part of an assessment:

- climate
- development densities
- development phasing
- ownership structure
- cost of construction
- energy and water utility rates

ABBREVIATIONS

Term	Definition
CUP	central utility plant
CHW	chilled water
CIRE	community integrated renewable energy
DEF	district energy feasibility
DHW	domestic hot water
EPA	environment protection agency
ETS	energy transfer station
EUI	energy utilization intensity
HHW	heating hot water
HRC	heat recovery chiller
IES VE	Integrated Environmental Solutions Virtual Environment
O&M	operations and maintenance
POPOS	privately owned public open spaces
SoMa	South of Market
ZNE	zero net energy

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APPENDIX A:
Model Assumptions

A1 IES VE Model Assumptions

Building Program and Load Data

Table 24. Geometry of the 6 Buildings within in the Community. Note: All Buildings Include 1 floor of Retail, Included in the Dimensions in the Table.

Building	Main Space Use	Height (ft)	Floors (ft)	Length (ft)	Width (ft)	Floorplate (ft^2)	Total (ft^2)
Building 1	Commercial	168	12	280	240	67,200	806,400
Building 2	Commercial	84	6	180	130	23,400	140,400
Building 3	Commercial	84	6	210	170	35,700	214,200
Building 4	Commercial	84	6	280	240	67,200	403,200
Building 5	Residential	98	7	350	130	45,500	318,500
Building 6	Residential	70	5	180	110	19,800	99,000
TOTAL						**258,800**	**1,981,700**

Table 25: Envelope (IES Default Values)

Construction	Description	U-value (Btu/[h·ft^2·°F])	R-value (h·ft^2·°F)/Btu
External Wall	Standard (2002 regs)	0.0616	15.3
Ground Floor	Standard (2002 regs)	0.0440	18.5
Roof	Flat (2002 regs)	0.0440	21.9
Windows	Low-e double glazing (6mm + 6mm) (2002 regs)	0.3482	2.87

Table 26: Fenestration

Commercial	80%
Residential	60%
Retail	60%

Table 27: Occupancy (IES Default Values)

Commercial	275
Residential	250
Retail	200

Table 28: Electricity Loads

Equipment (W/ft²)	**Commercial**	1.5	2013 ASHRAE Handbook Fundamentals
	Residential	0.5	Title 24 2010
	Retail	0.91	Title 24 2010
Interior Lighting (W/ft²)	**Commercial**	0.9	2013 ASHRAE Handbook Fundamentals
	Residential	0.6	ASHRAE Pocket Guide & Engineering Cookbook
	Retail	1.1	2013 ASHRAE Handbook Fundamentals

Table 29: Maximum Domestic Hot Water Consumption[21]

Space use	Peak (gal/[h·space])	Average (gal/[day·space])
Commercial	3.8	10
Residential	12.0	85
Retail	8.6	22

HVAC system

VAV reheat (Sys7) with CHW cooling, HW heat and reheat, outside air economizers, supply air temperature reset, energy recovery and return air plenums.

Table 30: HVAC System Efficiency

System	Energy Source	Efficiency
Cooling	Electricity	COP 6.1
Heating	Natural gas	82%
DHW Delivery		80%

21 A space is defined as 1/5 of a floor

Table 31: Specific Pump Power at Rated Speed

Pump	W/gpm
Hot water	19
Chiller water	22
Cooling tower	19

Weather Data

Building data and load profiles from ASHRAE 90.1 and weather files from San Francisco Airport were used in the simulations.

A2 DEF Model Assumptions

0. BAU BUILDING EQUIPMENT INPUTS

Cooling	COP	kW/Ton
Cooling Plant	6.40	0.55

Heating	% Efficiency
Heating Plant	80%

1. CUP EQUIPMENT INPUTS

Cooling	kw/Ton	COP
Vapor Compression Chillers	0.364	9.65
Absorption Chillers	1.00	3.5
Organic Refrigerant Chillers	0.70	5.02

Heating	% Efficiency
Gas Boilers	82%

CHP/CCHP (Turbine/Engine/Fuel Cell)	%
Thermal Efficiency	41.6%
Electrical Efficiency	45.1%
Max Turndown	85.0%
Max Heat Dumping	15.0%

Electric Only Fuel Cells	% Efficiency
Thermal Efficiency	20%
Electrical Efficiency	51.7%

Heating & Cooling		
Heat Recovery Chillers (Simaltaneous Cooling & Heating)	kw/Ton 0.60	COP 5.86
Exchange Efficiency	100%	%
Max. Turndown	40.0%	%

Heat Rejection Efficiency	kw/Ton	COP
Cooling Towers	0.053	66.30
Heat Dump Radiator	0.106	33.15

Cooling Towers		
Evaporation Rate	0.10%	
Drift Rate	0.0005%	
Blowdown Rate	0.05%	

2. DISTRICT / NETWORK INPUTS

Network Thermal Efficiencies	% Efficiency
CHW Network	97.0%
HHW Network	95.5%
CW Network	98.0%

District Pumping Inputs	Value	Unit
Pump Efficiency	80%	%
Motor Efficiency	90%	%
Average Network Pressure Head	1.75	ft/100 ft

CHW Network Inputs		
CHWS Temperature	50	F
Design Cooling Delta T	13.00	°F
Network Index Run Length	650	ft
Heat Exchanger Pressure Drop	15	ft
Valves, Fittings, Bends Loss	40%	% of Total Straight Pipe Loss

HHW Network Inputs		
Design Heating Delta T	35.00	°F
Network Index Run Length	650	ft
Heat Exchanger Pressure Drop	15	ft
Valves, Fittings, Bends Loss	40%	% of Total Straight Pipe Loss

CW Network Inputs		
Design Delta T	10.00	°F
Design Flow Rate	3.00	gpm/Ton
Network Index Run Length	650	ft
Heat Exchanger Pressure Drop	15	ft
Valves, Fittings, Bends Loss	40%	% of Total Straight Pipe Loss

3. BUILDING EQUIPMENT INPUTS

Heating & Cooling	kw/Ton	COP
Reversible Heat Pumps - Cooling	0.711	4.94
Reversible Heat Pumps - Heating	0.708	4.96
Reversible Heat Pumps - Cooling with Colder Bay/River Water	0.675	5.20

OPTION 4 | COGEN + CENTRAL HEATING AND COOLING

Cogen Inputs		
Operation Mode	Heat Led	
Prime Mover Type	Combustion	
Target Annual Run Hours (Electric or Heat Led)	6,500	Hours/Year
Thermal (Heat) Rating	25	kW
Electric Rating	27	kW

OPTION 5a | TRIGEN (Heating prioritized) + CENTRAL HEATING AND COOLING

Trigen Inputs		
Operation Mode	Heat + Coolth Led	
Prime Mover Type	Combustion	
Target Annual Run Hours (Electric or Heat + Coolth Led)	5,000	Hours/Year
Prime Mover Thermal (Heat) Rating	25	kW
Prime Mover Electric Rating	27	kW
Absorption Chiller Thermal (Coolth) Rating	25	kW
Absorption Chiller Heat Input Rating	7	kW

OPTION 5b | TRIGEN (Cooling prioritized) + CENTRAL HEATING AND COOLING

Trigen Inputs		
Operation Mode	Heat + Coolth Led	
Prime Mover Type	Combustion	
Target Annual Run Hours (Electric or Heat + Coolth Led)	1,880	Hours/Year
Prime Mover Thermal (Heat) Rating	25	kW
Prime Mover Electric Rating	27	kW
Absorption Chiller Thermal (Coolth) Rating	25	kW
Absorption Chiller Heat Input Rating	7	kW

OPTION 6 | BUILDING LEVEL HEATING AND COOLING PLANTS + CENTRAL FUEL CELLS

Fuel Cell Inputs		
Minimum Annual Run Hours (Electric or Heat Led)	6,000	Hours/Year
Electric Rating	200	kW
Heat Rating	77	kW

OPTION 7 | CENTRAL HEATING AND COOLING + FUEL CELLS

Fuel Cell Inputs		
Minimum Annual Run Hours (Electric or Heat Led)	6,000	Hours/Year
Electric Rating	200	kW
Heat Rating	77	kW

OPTION 8 | CENTRAL HEATING AND ENERGY RECOVERY CHILLERS

Heat Recovery Chiller Inputs		
Heat Recovery Chiller Rated Size	150.14	kW_{Cool}
Heat Recovery Chiller Minimum Cooling	60.05	kW_{Cool}

APPENDIX B:

B1 Life Cycle Cost Analysis

		BAU		District Energy Option 2	
DIRECT COST					
Exterior Closure		$	6,018,000	$	2,748,000
Building & Central Plant Equipment					
Heating					
Boilers		$	891,000	$	684,000
HHW Pumps		$	71,000	$	38,000
Heat Hot Water Heat Exchanger		$	-	$	134,000
Cooling					
Cooling towers		$	2,970,000	$	2,295,000
CW Pumps		$	95,000	$	47,000
Condenser Water Heat Exchanger		$	-	$	631,000
Chillers		$	2,242,000	$	2,064,000
CHW Pumps		$	167,000	$	86,200
Wet Distribution Systems		$	-	$	2,936,000
Other Items		$	2,275,000	$	2,239,000
Eletrical Service & Distribution		$	1,631,000	$	1,902,000
Total Direct Cost		**$**	**16,360,000**	**$**	**15,804,200**
INDIRECT COST					
Contractor Indirects / General Conditions	15.0%	$	2,454,000	$	2,370,630
Sub total		$	18,814,000	$	18,174,830
Contractor Overhead & Profit	10.0%	$	1,881,400	$	1,817,483
TOTAL CONSTRUCTION PRICE		**$**	**20,695,400**	**$**	**19,992,313**
SOFT COSTS					
Preliminary Engineering	2.0%	$	413,908	$	399,846
Final Design	6.0%	$	1,241,724	$	1,199,539
Project Management for Design & Construction	4.0%	$	827,816	$	799,693
Construction Administration & Management	4.0%	$	827,816	$	799,693
Professional Liability & Other Non-Construction Insurance	2.0%	$	413,908	$	399,846
Legal; Permits; Review Fees; Surveys, Testing,	1.0%	$	206,954	$	199,923
Total Soft Costs	**19.0%**	**$**	**3,932,126**	**$**	**3,798,539**
DESIGN AND CONSTRUCTION CONTINGENCY	**20.0%**	**$**	**4,925,505**	**$**	**4,758,170**

TOTAL PROJECT PRICE		$ 29,553,031	$ 28,549,023
Bid Factor		1.81	1.81
Minimum cost	-5%	$ 28,075,380	$ 27,121,572
Most likely cost		$ 29,553,031	$ 28,549,023
Maximum cost	25%	$ 36,941,289	$ 35,686,279

Owner Contingency	10.0%	$ 2,955,303	$ 2,854,902
TOTAL PROJECT PRICE WITH OWNER CONTINGENCY		$ 32,508,334	$ 31,403,925
Bid Factor		1.99	1.99
Minimum cost with owner contingency	-5%	$ 30,882,918	$ 29,833,729
Most likely cost with owner contingency		$ 32,508,334	$ 31,403,925
Maximum cost with owner contingency	25%	$ 40,635,418	$ 39,254,907

APPENDIX E:
Task 4- Energy Generation and Storage Analysis

Energy Research and Development Division
FINAL PROJECT REPORT

COMMUNITY INTEGRATED RENEWABLE ENERGY PROJECT

Task 4: Energy Storage and Generation Analysis

Prepared for: California Energy Commission
Prepared by: Arup, for the San Francisco Department of the Environment

ARUP

JUNE 2014
CEC-500-2014-JUN

CHAPTER 1: Introduction

Project Description

The Community Integrated Renewable Energy (CIRE) Project will assess the feasibility of community energy, district heating and cooling, renewable electricity, storage and energy recovery, demand response, and microgrid distribution technology to serve community members and their energy needs.

The CIRE Project consists of the following tasks and subject areas:

- Task 1: Administrative and Reporting
- Task 2: Distributed Generation Connected to the Electricity Network
- Task 3: Community Generation and Enabling Technologies
- Task 4: Energy Storage and Generation Analysis
- Task 5: District Thermal Energy Concept

This report provides our preliminary findings for Task 4: Energy Storage and Generation Analysis.

The goal of this task is to conceptually identify suitable generation and electricity storage technologies and the requisite sizes that would provide energy to community members in the event of an electrical outage. Three scales of community members and two scales of outage duration are analyzed in this report.

The scales of building that are analyzed in this report are:

- Convention center scale
    - Potential for use in disaster recovery and sheltering
- Single building scale
    - Single commercial building
- Community scale
    - Mixed commercial and residential buildings

For each of the above scales of development, the two outage durations assessed were 5 hours and 72 hours.

The goal was achieved through the following tasks:

- Investigate and document the resilience criteria to maintain electricity supply during outages
- model energy generation and storage options to meet resilience criteria
- provide high-level economic analysis for the generation and storage assets

CHAPTER 2:
Resilience Criteria

Electricity Outage Frequency

This goal of this report is to define what generation and storage technologies are required to provide buildings and communities with electricity during grid outages. In order to determine the resilience criteria that would be assessed in the scenario, the project team investigated utility data and disaster preparedness plans in California to ensure that the most appropriate metrics were used in the analysis. Table 1 provides a summary of the outage conditions assessed in this report.

Table 1: Outage Duration Summary

Outage	Duration (hrs)
Short-term	5
Long-term	72

Short-term Outage

For short-term, nonemergency outages utility data were used in order to quantify realistic outage duration for electricity customers in California. The three investor-owned utilities (IOUs) that operate in California[1] along with Pacific Power[2] provide annual reports to the California Public Utilities Commission (CPUC) stating the reliability of the electric system. The reports are published on the CPUC website.[3]

The reports include three measurements to enable reliability assessments. SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) values include sustained outages, which are defined as outages lasting 5 minutes or more. MAIFI (Momentary Average Interruption Frequency Index) values include momentary outages, which are defined as outages lasting less than 5 minutes.

The units for the reliability measures are as follows:

- SAIDI – minutes of sustained outages per customer per year
- SAIFI – number of sustained outages per customer per year
- MAIFI – number of momentary outages per customer per year

[1] Pacific Gas and Electric, San Diego Gas & Electric, and Southern California Edison

[2] Pacific Power serves approximately 45,000 customers in California.

[3] http://www.cpuc.ca.gov/PUC/energy/ElectricSR/Reliability/annualreports/

The SAIDI measurement is the most interesting index for quantifying the duration of an average outage for the purposes of this report. Table 2 details the SAIDI performance for each individual utility that operates in California.[4]

Table 2: SAIDI Performance in California (Major Events Included)

Year	SAIDI			
	PG&E*	Pacific Power	SDG&E†	Edison‡
2004	205	674	93	75
2005	249	594	62	92
2006	281	622	53	142
2007	160	516	182	151
2008	416	932	59	119
2009	208	331	67	106
2010	246	1,188	90	141
2011	276	277	568	232
2012	139	502	64	108
2013	115	317	75	103
Individual Average (hours)	4	10	2	2
All Average (hours)				5

*Pacific Gas and Electric
† San Diego Gas & Electric
‡ Southern California Edison

The average outage of the utilities that report SAIDI statistics is 5 hours. This number will vary from year to year and from utility to utility. The outage duration of 5 hours is used as the short-term outage duration for the analysis performed in this report.

Long-term Outage

During Task 3a, the team held a workshop that included a discussion of long-term resilience criteria.[5] The workshop group concluded that San Francisco's disaster planning efforts should accommodate a 72-hour electricity outage. The San Francisco Department of Emergency Management developed SF72 to function as the city's hub for disaster preparedness.[6] The name

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[4] Only IOUs are required to report to the CPUC. Municipal utilities are not required to report. Therefore these numbers account for approximately 75% of the electricity supply in California.

[5] See Task 3a report for more details.

[6] http://www.sf72.org/home

SF72 refers to how, in disasters such as earthquakes, City services will be impacted to such an extent that residents should be able to look after themselves for 72 hours. While such long power outages are rare, they can also happen during nondisaster situations. The list that follows summarizes the highest duration outages that were reported in 2013 for each utility:

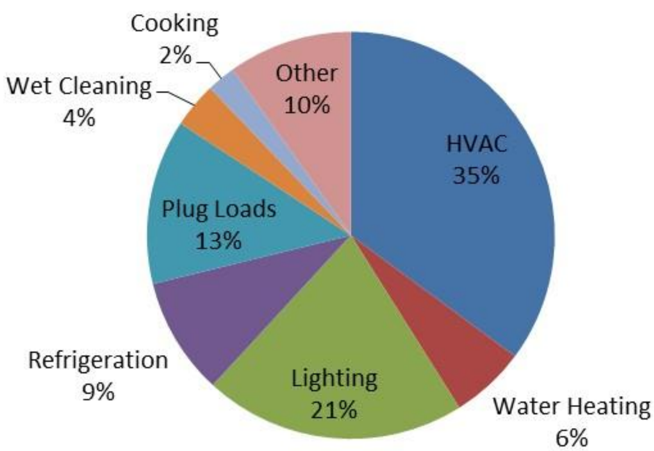
- PG&E – 385,017 customers experienced a sustained outage. The time to reconnect all customers was 6 days.
- SDG&E – 25,534 customers experienced a sustained outage. The time to reconnect all customers was 5 days.
- Southern California Edison – 99,290 customers experienced a sustained outage. The time to reconnect all customers was 4.5 days.
- Pacific Power – 458 customers experienced a sustained outage. The time to reconnect all customers was 0.5 days.

The outage duration of 72 hours is used as the long-term outage duration in the analysis performed in this report. The primary reason for this length of time is to align with San Francisco's disaster preparedness plans.

Outage Load Operation

This study quantifies the generation and electricity storage sizes needed in order to allow a building to operate some of its electrical loads in absence of utility power. As discussed above, the outages modeled in this report are of 5 hours and 72 hours duration.

Figure 1: Commercial and Residential Electricity Use



Source: Buildings Energy Data Book: Table 2.1 2010 Residential Sector Energy and Table 3.1 2010 Commercial Sector Energy[7]

[7] (Department of Energy, 2012)

Figure 1 shows how electricity is used in buildings in the U.S. Heating, ventilation, and air conditioning (HVAC) and lighting and plug loads (e.g. computers, televisions) are the largest consuming loads in the built environment. The values in Figure 1 are annual electricity consumption figures although the instantaneous load at any one time may reflect a differing end-use. The load values in Figure 1 were used to determine areas of load reduction in the event of an electricity outage.

For the short-term outage of 5 hours, we modeled that 80% of all electrical loads are to remain operational. In this scenario we have assumed that 50% of the lighting load is switched off to save energy, resulting in a 10% reduction of the buildings' load. Reducing lighting levels by 50% is assumed to be via bi-level lighting or a similar strategy. In addition, for this short duration outage, HVAC electrical capacity is reduced by a third. This will reduce the capacity of the HVAC system for cooling.

For the long-term outage of 72 hours, we modeled that 60% of all electrical loads are to remain operational. In this scenario we have assumed that 50% of the lighting load is switched off to save energy, resulting in a 10% reduction of the buildings' load. Reducing lighting levels by 50% is assumed to be via bi-level lighting or a similar strategy. In addition, for this long duration outage, HVAC electrical capacity is reduced by 50%. This will reduce the capacity of the HVAC system for cooling. For commercial applications or large residential towers with building level cooling, we assumed that all water systems such as chillers are inhibited from operating but the ventilation fans remain in operation to ensure air flow. For a long-term outage, reducing lighting and cooling will only allow the load to be reduced by 28% and more loads will require management. Some loads are also reasonable to reduce in a long-term outage, such as plug loads and others[8]. A reduction of 50% in both of these categories will allow some essential technologies such as radios, television, computers, and the internet to remain operational in the extended outage and provide vital information and communications to the building occupants. The above strategies reduce the total load by 40%.

The effect of the proposed cooling reduction to building occupants will greatly depend upon where in California the building is located. For buildings in San Francisco on a typical San Francisco day, building occupants would likely notice little difference in the operation of the building for the short 5-hour duration and would still receive comfort from the air flow for longer duration outages. However, if the building was installed in a hot central valley location in summer, then there would be changes to building temperatures for both the short-term and the long-term outages.

When implementing a load management system for resilience, the local climate will play an important role in selecting the load reduction strategy. In addition to the climate, the make-up of the individual building or community will also play a role. The load management criteria

[8] Other loads Includes small electric devices, small motors, heating elements, swimming pool heaters, hot tub heaters in the residential built environment and includes service station equipment, ATMs, telecommunications equipment, medical equipment and pumps in the commercial sectors.

should be tailored to each individual building and will be a function of the buildings' loads and what is important to the building occupants.

For both outage scenarios, varying the electrical load that is required in an outage will vary the generation and electricity storage mix needed to meet the resilience criteria.

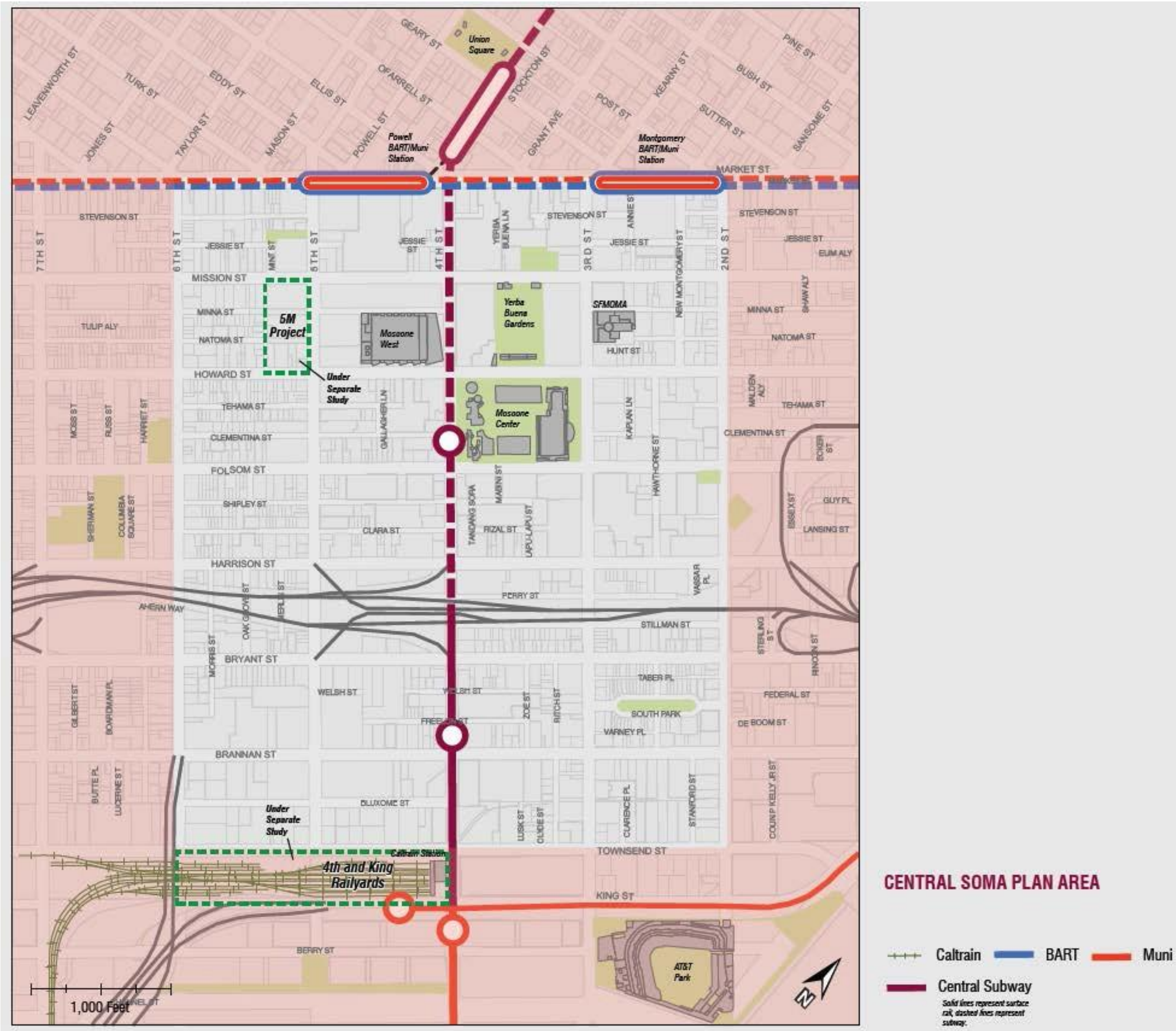
CHAPTER 3: Building Selection

Central SoMa Introduction

In San Francisco, 56% of greenhouse gas emissions are associated with lighting, heating, and cooling buildings. The City and County of San Francisco (CCSF) is committed to developing and implementing aggressive and diversified approaches to reducing these emissions, while continuing to absorb anticipated regional population growth. One such approach is to plan carbon-free community-scale energy resources locally and regionally. Another is to increase jobs and housing in transit-oriented neighborhoods.

Central SoMa is a dense, transit-rich area of San Francisco that extends from Second Street to Sixth Street and from Market Street to Townsend Street. The area has been identified as a priority development area by the Planning Department and is the subject of a significant rezoning effort that encourages sustainable growth, which in turn creates substantial opportunities to align energy, transportation, water, and waste infrastructure systems. In addition to identifying the renewable energy resources and enabling technologies that could be appropriate for this district, the CIRE Project will identify ways that CCSF can advance community-scale energy in this neighborhood. These efforts include providing a strategy to coordinate multiple public and private interests, including identification of all key institutional stakeholders and relevant regulatory frameworks.

Figure 2: San Francisco Central SoMa



Source: CCSF Planning Department

With the addition of the Central Subway along and under Fourth Street (under construction and scheduled to begin operation in 2018), undeveloped or underdeveloped parcels in the transit corridor offer a major development opportunity. CCSF anticipates approximately 12,000 new housing units and 35,000 jobs in this area. The Central SoMa Plan, released in draft in April 2013, proposes rezoning this area for dense, transit-oriented, mixed-use growth and provides opportunities to capitalize on rezoning in order to incorporate district-level energy infrastructure.

In addition to providing local energy, creating CIRE projects will greatly enhance the resiliency of Central SoMa. The ability to generate power and provide local energy is essential for both the immediate and the long-term recovery from a large earthquake or a similar disaster.

The Central SoMa CIRE Project has the potential to inform similar planning efforts in other parts of the state, particularly those with new development areas, major infrastructure projects, and significant revitalization plans, as well as existing neighborhoods.

Central SoMa Modeled Buildings

Central SoMa contains a diverse mix of buildings. This report uses two building-type models to determine the scale of generation and storage assets to meet resilience criteria: a Building Scale (Moscone West) and a hypothetical newly-built[9] community development in South Central SoMa.

Convention Center Scale

This scenario was studied to explore how a large building, capable of sheltering members of the public, could achieve energy resiliency through the application of generation and storage technologies. The Moscone West building, part of the Moscone Center in downtown San Francisco, was chosen as a representation of buildings with multiple-hundred-thousand-square-foot ranges and as a representation of similar convention centers in urban settings that exist throughout California.

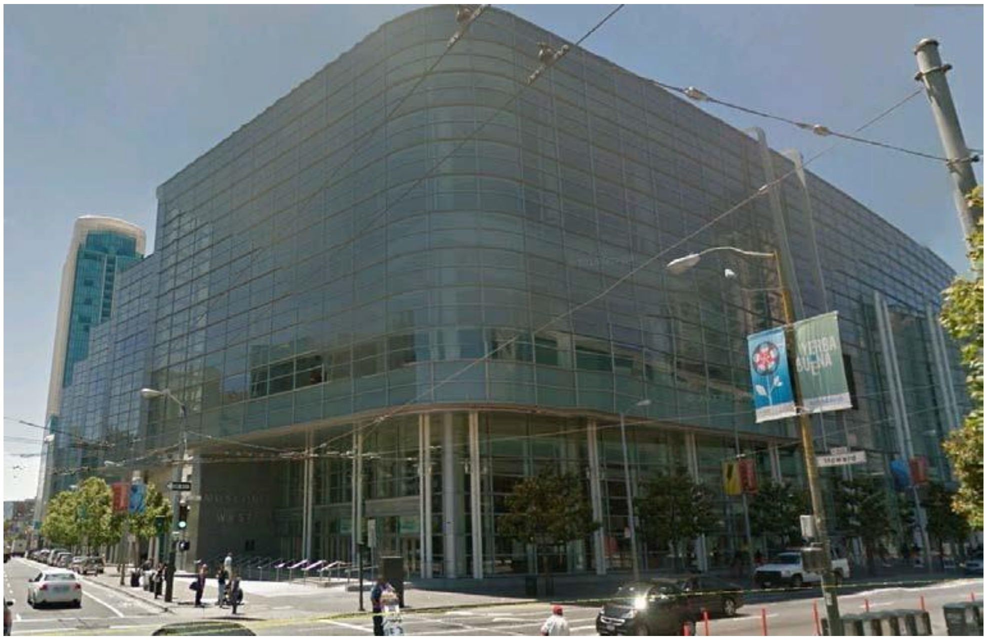
In summary, Moscone West includes the following:

- a total property floor area of 380,000ft^2
- three floors with a total height of 110ft
- exhibit spaces, meeting rooms, and lobbies
- a roof area of 62,500ft^2

The building was chosen because it is a large, mixed-use building that could theoretically function as a disaster relief shelter if necessary. Energy resilience in an electrical outage could aid in San Francisco's disaster resource planning and this type of building could be used throughout California for the same purpose. Moscone West's large, open spaces could effectively shelter many residents. Energy resilience is of great importance for such buildings. Therefore, Moscone West was seen as a suitable representative candidate for this study.

[9] Due to the areas up-zoning. The new development replaces existing low rise industrial development.

Figure 3: Moscone West



Source: Google, Inc.

As Moscone West is an existing building, hourly electricity data are available. These data were used to size the generation and storage assets.

Single Building and Community Scale

A single building was assessed in order to understand how one commercial building, such as an office building, could continue to function in the event of an outage. This functionality could allow business continuity for a high-value business or provide shelter to a workforce and their families in times of extended outages. The community-scale scenario was studied to explore the impact of scale on the ability to achieve resiliency and to determine if scale and mixed-use developments are more cost-effective due to their ability to pool resources.

A fictitious six-building, mixed-use district was used to represent the community-scale scenario. Such a mix of buildings adequately represents new development planned in Central SoMa as it reflects the upzoning identified in the Central SoMa Plan. The building mix was developed for the Flower Market area of San Francisco and uses buildings of a scale zoned in this area.

The single building that was assessed was the largest commercial building within the development. This single building could represent a microgrid trial within a newly built community or could represent a member of the community who values energy security and has invested additional funds toward making the building resilient.

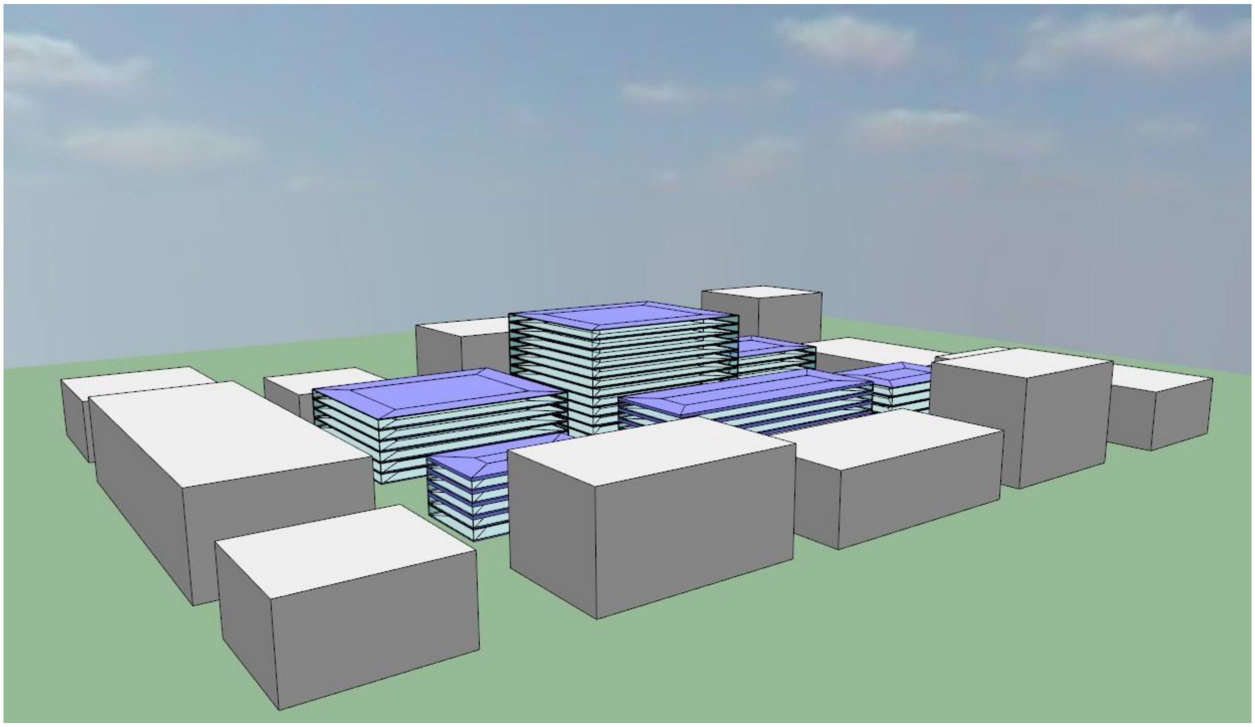
Figure 4: Existing Flower Market Area of Central SoMa

Source: Google, Inc.

In order to generate electrical load data for the purposes of this study, the community-scale scenario was modeled in the Integrated Environmental Solutions (IES) Virtual Environment (VE) software package, as illustrated in Figure 5.[10] The purple buildings represent the community that was studied, while the gray buildings were included in the model to represent neighboring blocks. The tallest of the buildings in this model represents the single-building scale in this study.

[10] http://www.iesve.com/software

Figure 5: Flower Market Development



Source: Arup

The community-scale scenario includes the following:

- a total property floor area of 1,530,000ft^2
- a 67% commercial, 20% residential, and 13% retail area split (all retail on ground floor)
- a floor-to-floor height of 14ft in all buildings
- varying building heights between 65ft and 130ft
- neighboring existing buildings (included in model only for shading purposes)

The community buildings are all assumed to be newly constructed, high-performance buildings that exceed California’s Title 24 requirements. They are also assumed to be developer-led buildings and as such include forced air overhead variable air volume systems.

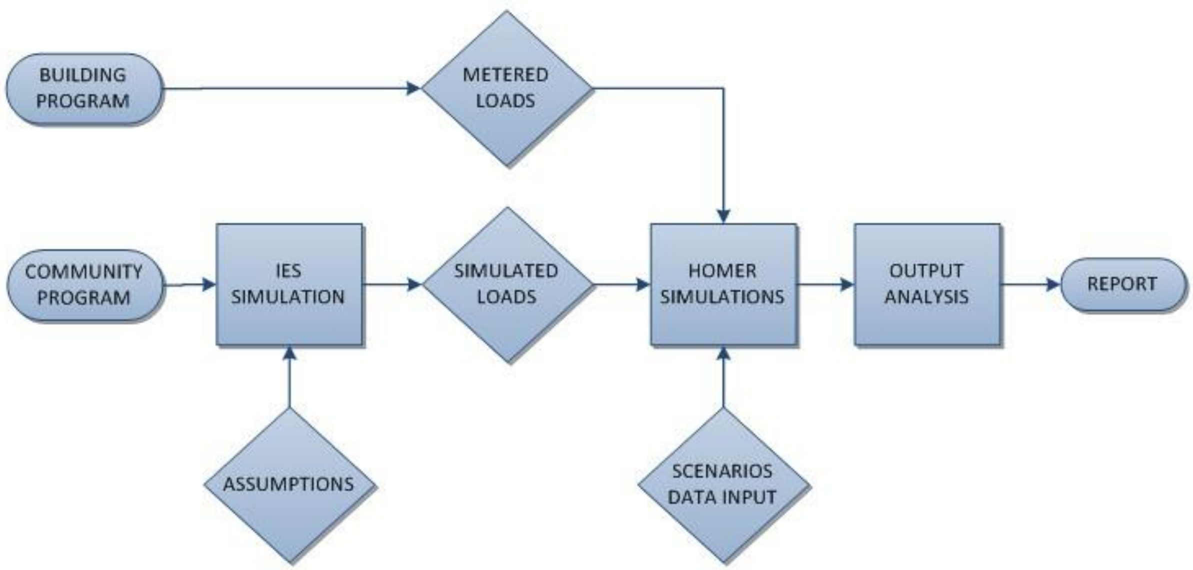
For the single building, a commercial building of 550,000ft^2 was chosen which includes first floor retail-tenanted space.

CHAPTER 4: Methodology

Process

Figure 6 illustrates the process used to carry out the modeling for this task to size the generation and storage assets based on the resilience criteria. The electrical loads for the building-scale scenario were obtained directly through the use of metered data. The electrical loads for the single building and the community-scale scenarios were simulated using the IES VE energy modeling software.

Figure 6: Study Process



Simulations in HOMER

Simulations of the different energy generation and storage scenarios were performed using the Hybrid Optimization Model for Electric Renewables (HOMER) software, developed by the National Renewable Energy Laboratory (NREL).

HOMER is a tool used for designing micropower systems and for facilitating the comparison of different power generation and storage technologies. HOMER considers the economic and technical feasibility of the studied system and models it from a life-cycle point of view.

The user creates a model in HOMER by adding the generation and storage technologies of interest and then by entering the inputs for the component costs and the resource availability for these technologies. In the simulation, HOMER calculates the flows of energy to and from each component for all 8,760 hours in a year. It also calculates how the generators and batteries are operating for each hour.

For each system, HOMER simulates many different system configurations, discards the ones that cannot meet the electricity demand, and calculates the net present cost. The net present cost reflects the project life-cycle cost, which is the total cost of installing and operating the system over its lifetime. The results are presented in order of net present cost, with the most economically optimal system configuration at the top of the list. This list makes it possible to compare different system configurations in terms of example costs, fraction of generation from renewables, and fuel consumption, et cetera.

HOMER offers the possibility of simulating both grid-connected and autonomous systems. This study is focused on resilience during times when the grid is not available (a 5-hour and a 72-hour power outage). However, HOMER does not allow simulations over shorter time periods than the minimum project lifetime, which is one year. A grid-connected system was therefore applied. The outages were simulated by increasing the grid rates to infinity during the hours of outage, thereby forcing the microgrid to operate without the grid. The simulations in HOMER are performed over a project lifetime of 25 years. The purpose of this was to include the different lifetimes and replacement costs for the studied generation and storage technologies.

When creating a generator such as a diesel generator or a fuel cell, the following properties need to be defined in HOMER: AC or DC generation, fuel type and fuel curve, maximum and minimum electrical power output, and lifetime in operating hours. It is possible to schedule when the generator should be turned on or off, but it is also possible to let HOMER optimize the hours of operation depending on electricity demand and the costs of other available power sources.

When modeling a PV array, HOMER assumes DC electricity production in direct proportion to the global solar radiation at the defined location for each hour of the year. Lifetime, derating factor, tilt angles, orientation, and reflectance must also be defined.

For systems with a battery bank and at least one generator, there are two options for how the system charges the batteries (dispatch strategies):

- Load-following, where the generator only produces enough electricity to meet the load and the batteries are only charged by the renewables and not by the generator.
- Cycle-charging, where the generator produces more electricity than what is needed to meet the load and charges the battery with the surplus electricity.

Cycle-charging was used in this study in order to let the generator charge the storage up to a 50% state of charge. This limitation aims to leave space for excess electricity produced in the PVs.

To ensure that the electricity storage is fully charged when a power outage happens in the model, the batteries were set to discharge only when the grid price increased over a certain value corresponding to a power outage in the model.

Modeled Scenarios

The CIRE Project has core goals of increasing renewable and low carbon generation in urban centers. Therefore, this form of generation is maximized in the modeling.

For each of the scenarios in this study, the sizes of the generation technologies were fixed while the size of storage technology was set to vary in order to find the necessary storage size as well as the cost for such a system. Renewable generation (PV) was maximized to cover all of the roofs of the studied buildings. The generation and storage chapter describes the sizing process used to define the generation and storage assets.

The results are analyzed and the feasibility of each scenario is determined. In this study, the feasible scenarios are defined as the scenarios that meet the requirements for the maximum storage sizes stated in this document.

For each scenario, all the different system configurations that could meet the load were collected and presented in scatter plot charts in the results chapter. For each of the infeasible storage scenarios, a second simulation was performed to study the load reduction needed for the storage size to become feasible.

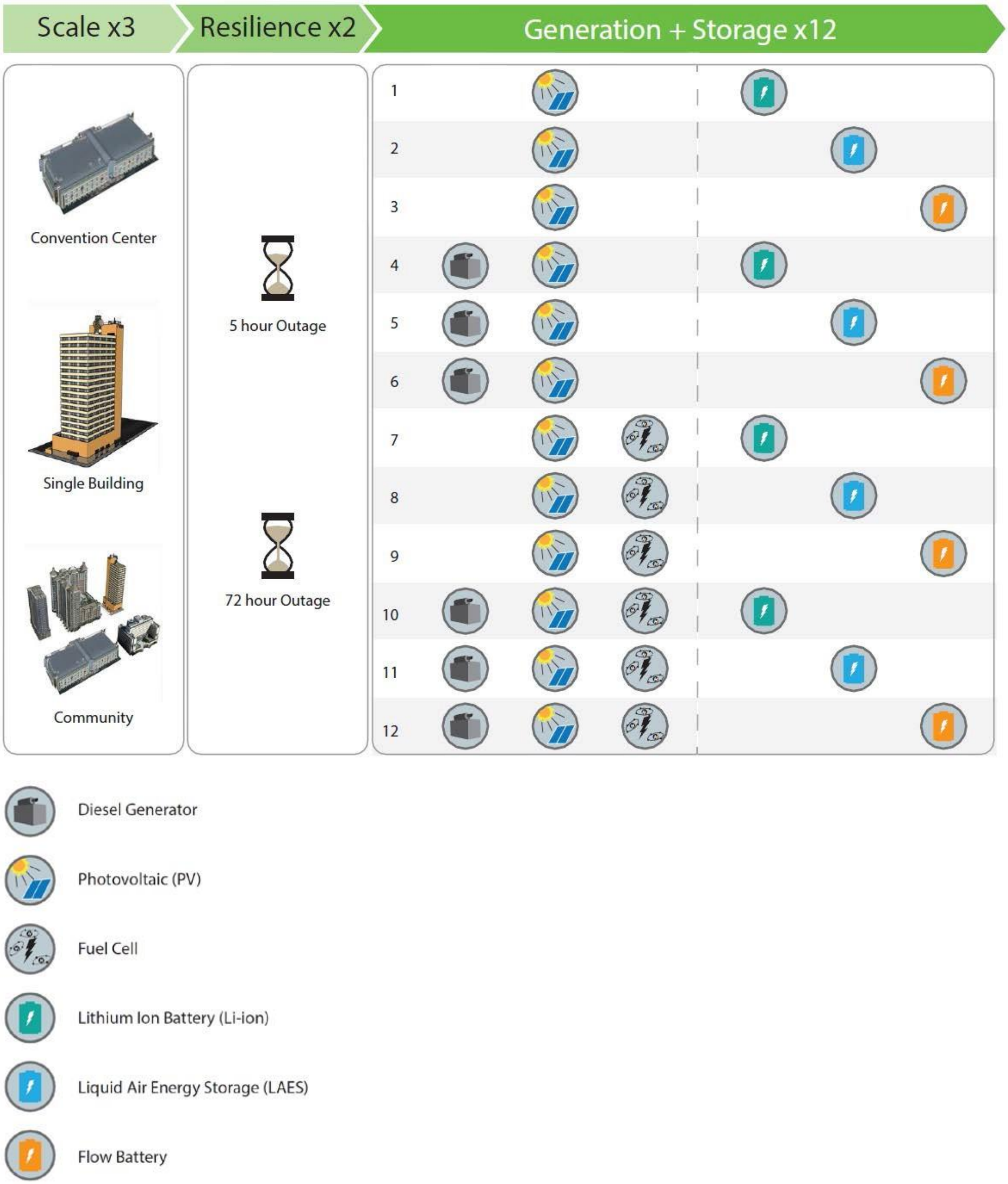
All assumptions and data inputs used in the simulations are summarized in Appendix B.

In an effort to inform a range of building scales and technologies, this study considered 72 scenarios, which comprised combinations of the following:

- 3 scale scenarios
    - convention center scale
    - Single building scale
    - Community scale
- 2 resilience scenarios
    - 5-hour outage
    - 72-hour outage
- 12 generation and storage scenarios using various technologies stated in this chapter (3 generation and 3 electricity storage technologies).

These study combinations are illustrated in Figure 7.

Figure 7: Study Combinations



Electricity Profiles

Convention Center Scale

Fifteen-minute-interval metered electrical load data for a convention center (Moscone West) was used directly to create the electrical loads in this scenario. The duration curve and the monthly electrical load are presented in Figure 8 and Figure 9. The base load for Moscone West is unusually high, with a year-round minimum load of approximately 500kW. This may represent opportunities for control and setback-based energy reductions for Moscone West, which are outside the scope of this task.

Figure 8: Duration Curve of the Convention Center (Moscone West)

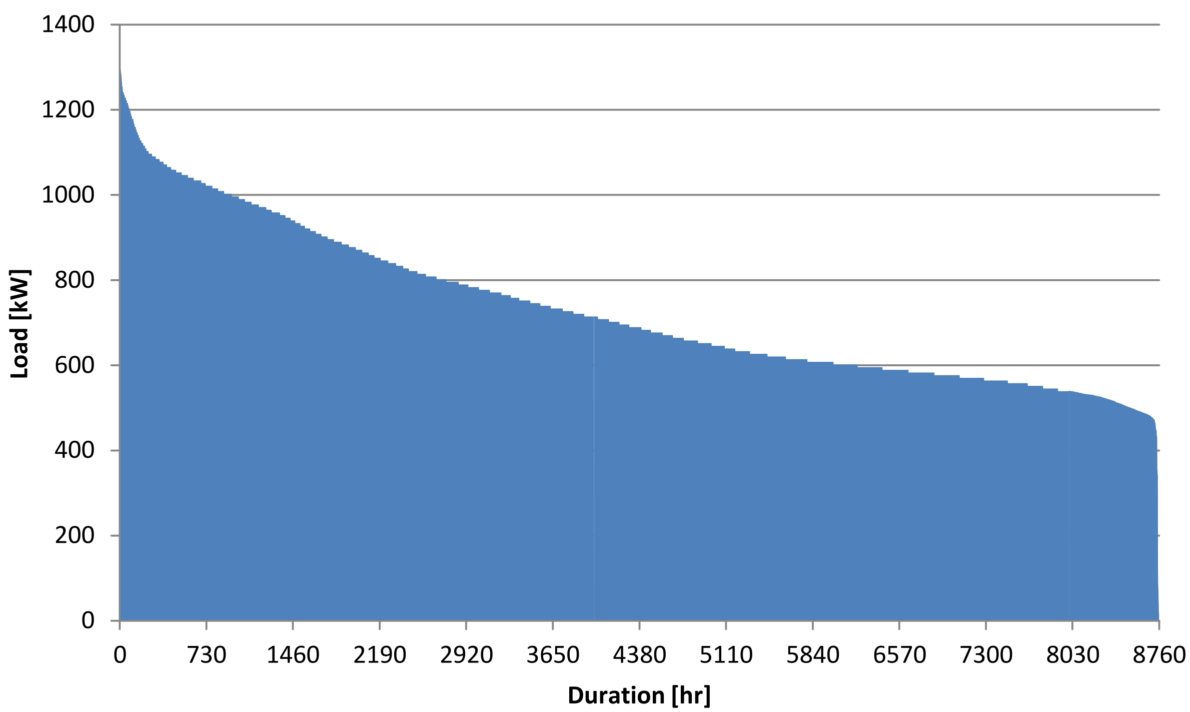
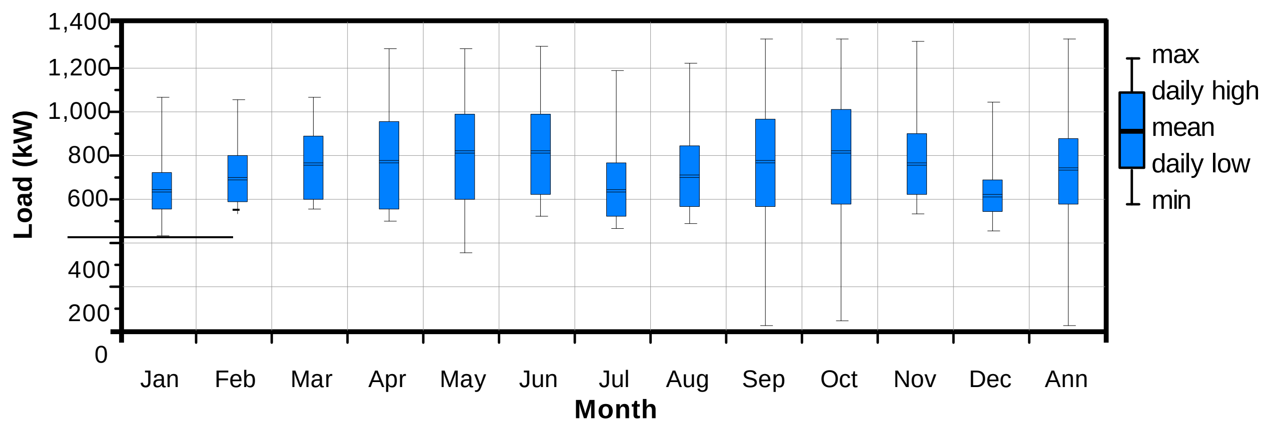


Figure 9: Monthly Average Loads of the Convention Center (Moscone West)



There are some obvious seasonal variations in the electricity load. The lower loads between July and August and between December and January are likely correlated to vacation and holiday seasons when there are fewer events at the Moscone Center.

Moscone West is equipped with a 1MW diesel generator that supplies the building with emergency power. This generator is connected to a 2,000-gallon fuel storage tank, which is equivalent to approximately 24 hours of emergency power generation at full generator capacity.[11]

There is no existing renewable energy generation at Moscone West, even though the building has a large, flat roof with significant opportunity for large-scale PV or other assets such as fuel cells/electricity storage.

The Moscone West building is located within the secondary network in San Francisco. A secondary network offers a higher level of electrical resilience to a building as the building is supplied from many utility transformers. This means if there was an outage to one transformer, the building load is seamlessly provided by another transformer. However, one issue with a secondary network is that the type of protection utilized to make the system safe prevents energy from being exported at any time. This protection makes large-scale renewable generation more difficult to integrate as there is a risk of exporting power during periods of low building demand and high renewable generation. The Task 2 report, Technical and Cost Implications of Renewables, provides details on the issues of a secondary network and some methods that may be investigated to increase renewable generation penetration, such as load-following inverters and reverse-power relays.

Single Building Scale

A single commercial building in San Francisco was modeled in order to present the electrical load of a typical commercial building.

The duration curve and the monthly electrical load are presented in Figure 10 and Figure 11, based on the loads generated in IES VE. Further details on the building dimensions and energy IES VE model input assumptions are described in Appendix A.

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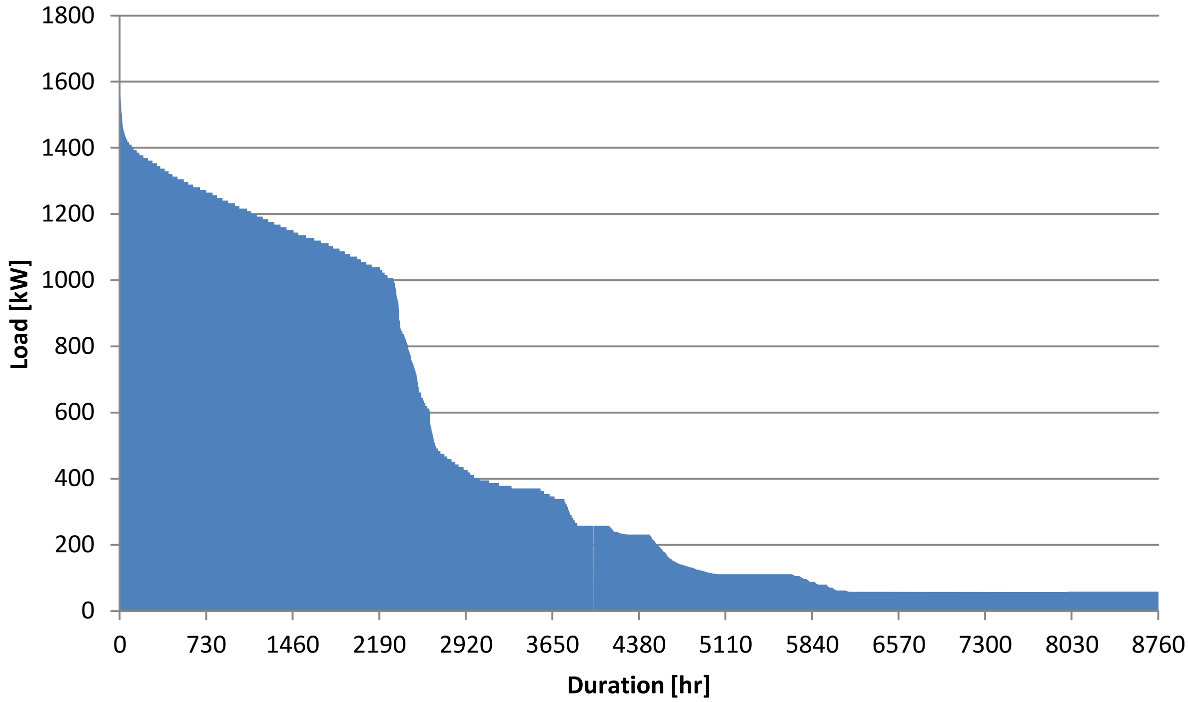
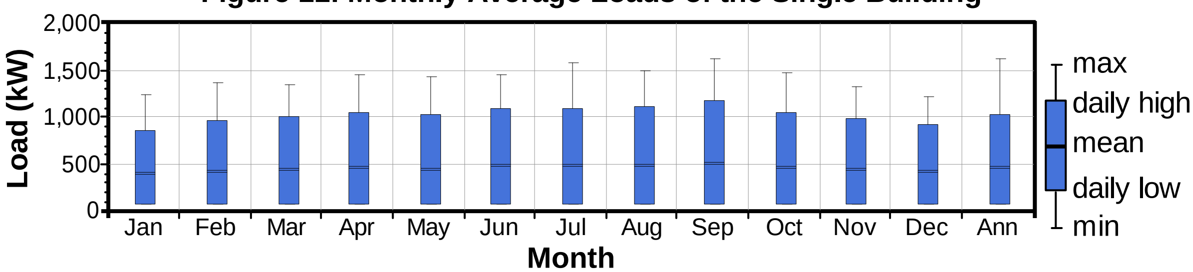
[11] Moscone Center, 2012

Figure 10: Duration Curve of the Single Building



This duration curve, with a very low base load, is typical for commercial buildings.

Figure 11: Monthly Average Loads of the Single Building



Certain seasonal variations in electrical load are immediately evident in Figure 11, such as the increase during summer months, which is a result of air-conditioning demand.

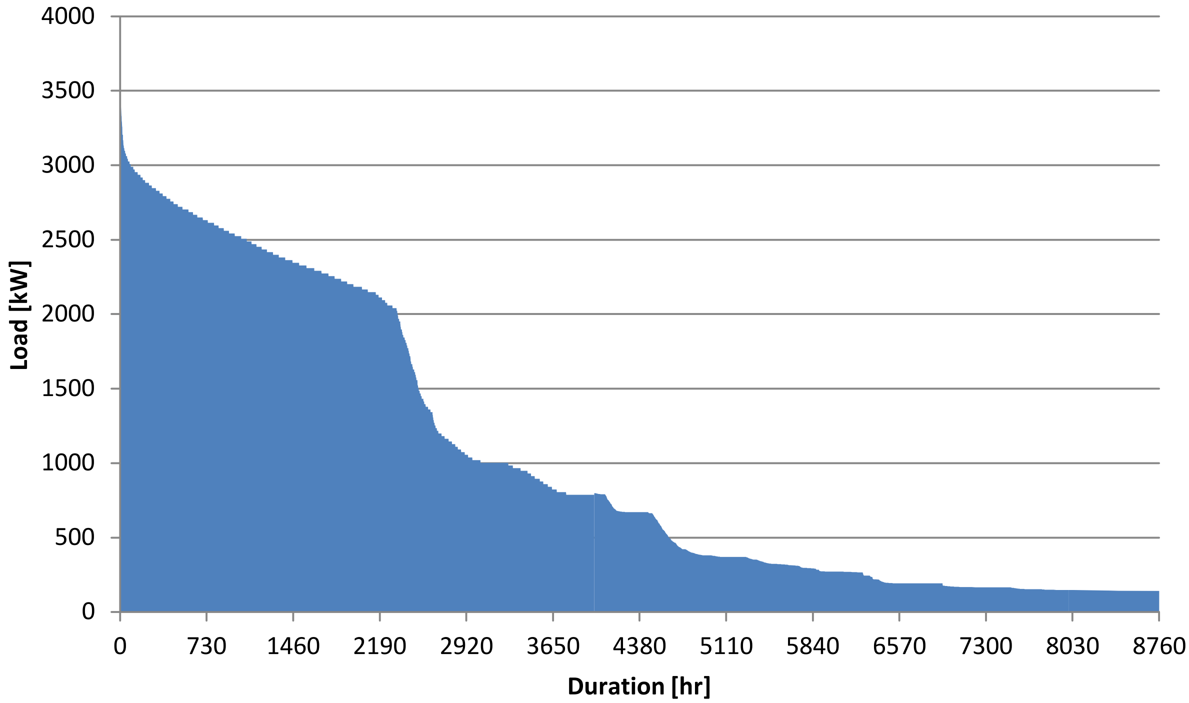
Community Scale

The community-scale model takes into account all of the buildings in the community and presents them as a single combined load (as the utility would see them in aggregate), which enables the demonstration of community-scale generation and storage.

The duration curve and the monthly electrical load are presented in

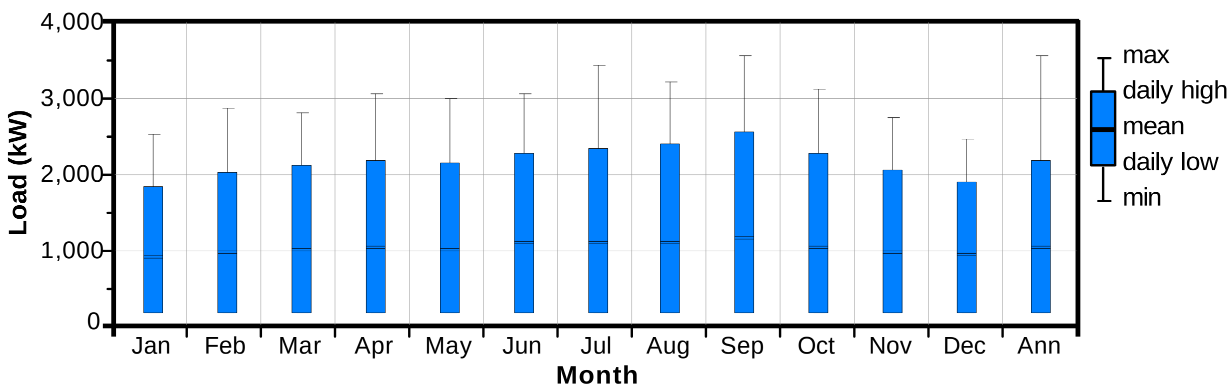
Figure 12 and Figure 13 and are based on the loads generated in IES VE. Further details on the building dimensions and energy IES VE model input assumptions are described in Appendix A.

Figure 12: Duration Curve of the Community



This duration curve is typical for communities with a mixture of commercial and residential buildings.

Figure 13: Monthly Average Loads of the Community



Just like the single building scale, certain seasonal variations in electrical load due to air-conditioning demand are immediately evident in Figure 13.

It is assumed that there are public roads that surround the community buildings as well as separate them from each other, as is common in such urban settings. Similarly, it is most common for such buildings to have different owners, which when coupled with the public rights-of-way, creates legal hurdles related to power distribution.[12]

[12] See Task 2 report for more details.

CHAPTER 5: Generation and Storage Technologies

The scope of this task called for the investigation of three generation and three storage technologies that can be used in combination to meet the resilience criteria set out in this document. The electrical generation technologies assessed are as follows:

- diesel generators
- fuel cells
- PV

The electrical storage technologies assessed are as follows:

- lithium-ion batteries (li-ion)
- liquid air energy storage (LAES)
- flow batteries

Diesel Generators

A diesel generator is a combination of a diesel engine and an electric generator where the diesel engine produces mechanical energy that is converted into electrical energy by the generator. Diesel generators are often used in places without access to the electrical grid or for generating emergency power in case of a power outage. Electrical code in California identifies legally-required loads that shall be powered in the event of a power outage. For larger buildings and high rises, these legally required loads are often provided by diesel generators. Smaller buildings with only egress lighting needs may utilize batteries installed in the lighting fixtures instead.

For the convention center scale, the Moscone West has an existing 1 MW generator that is installed for life safety loads and can also maintain other selected loads within the center. As the Flower Market area is a fictitious development, an estimation determines the typical generator size that would be installed for life-safety-only loads in a high-rise building.

Based on a review of past building projects in California, a typical generator size for a high-rise building is approximately 1.8 W/ft^2, which meets about 76% of the peak load.

In this study the diesel generators are assumed to have diesel storage large enough to supply the generator for 24 hours running at full capacity. For the 72-hour power outage scenario, it is therefore assumed that the generators can only run at full load for a period of 24 hours within this 72-hour period and that no fuel is delivered during the power outage. To include this in the HOMER simulations, the diesel consumption was limited to a third of what the generator should have consumed if it was running at full capacity during the hours of power outage in the model.

The generator sizes used for each scale scenario are presented in Table 3. The generators are not large enough to meet the criteria for the two resilience scenarios and require additional generation to maintain the loads.

Table 3: Generator's Capacity Fraction

Scale Scenario	Generator Size (kW)
Convention Center	1,000
Single Building	1,000
Community	2,750

The costs for diesel generators used in this study are presented in Table 4. Since the generator is only running during power outages, the lifetime is going to exceed the project lifetime in the HOMER simulations (25 years). The replacement cost can therefore be set to zero.

Table 4: Diesel Generator Costs[13]

Costs		
Capital	1,500	$/kW
Replacement[14]	0	$/kW
Operations and Maintenance (O&M)	0.05	$/kWh
Fuel (diesel) [15]	4.1	$/gallon

Figure 14 shows a typical diesel generator installed on an Arup project within an acoustic enclosure.

[13] HOMER default values

[14] Due to limited run times, it is reasonable to assume that diesel generators will not be replaced over the study horizon as they are operated only in an emergency and are not used at any other times. This is not true of the fuel cells and electricity storage

[15] eia, 2014

Figure 14: Typical Generator Installation

Fuel Cells

Fuel cells operate by combining hydrogen with oxygen in an electrolyte between an anode and a cathode in the presence of a catalyst. The migration of protons and electrons that follows causes a transfer of charge that appears as a voltage across the electrodes. The by-products of the reaction between the hydrogen and oxygen are heat and water.

Solid oxide fuel cells were assumed for the purposes of this study. This type of fuel cell uses a solid oxide material as the electrolyte and operates at very high temperatures, typically between 500°C and 1000°C. As a result, solid oxide fuel cells have an electrical efficiency approaching 55%. Bloom Energy is one such producer of commercial solid oxide fuel cells.

Hydrogen obtained from natural gas reformation was assumed as the fuel source for this study. In order to make this a renewable fuel cell, biogas or directed biogas can also be used. However, this will increase the costs of this form of generation. This enables the fuel cells to operate at full capacity during a power outage, at which time natural gas supply is assumed to be unaffected. In the event of a severe natural disaster such as an earthquake, the natural gas infrastructure may experience outage, which would reduce the resilience offered by a generator utilizing natural gas without on-site storage.

Fuel cells are designed to operate constantly, and the technology is best suited to a fixed, constant load. The fuel cells are therefore sized to meet the base load of the building(s), and the size for each scale scenario is therefore assumed to be fixed, as summarized in Table 5. These fixed sizes were calculated from the electricity data received from the Moscone Center and from the IES model output for the building and community-scale examples.

Table 5: Fuel Cell Capacity

Scale	Fuel Cell Size (kW)
Convention Center	600
Single Building	60
Community	250

The costs for fuel cells used in this study are presented in Table 6.

Table 6: Fuel Cell Costs

Costs		
Capital[16]	7,000	$/kW
Replacement[17]	6,300	$/kW
O&M[18]	0.133	$/kWh
Fuel (natural gas)[19]	0.32	$/m^3

Fuel cells are manufactured as modular products and the two most common fuel cells on the market are the Bloom solid oxide fuel cell and the Clear Edge Power's phosphoric acid fuel cell. Typical sizes that would be suitable for the scale of outputs modeled in this scenario would be the 200kWe modules that Bloom produces or a combination of a Bloom unit and the 400kWe unit that Clear Edge Power produces. The Bloom fuel cell produces only electricity, while the Clear Edge Power device has the advantage of also providing useful heat output. The Bloom device has a footprint of 30ft by 8ft for the module and additional space needs for ancillary equipment, access, and maintenance, resulting in a total space-take of around 650ft^2. The fuel

[16] Arup quote from various manufacturers of both solid oxide and phosphoric acid fuel cells

[17] Estimation that the fixed equipment such as electrical switchboards, concrete mounting pads, and ancillary items make up 10% of the total capital cost

[18] Wesoff E., 2013

[19] California Energy Commission

cell can be installed outside of a building, within a building, or on the roof of a building, as shown in Figure 15.

Figure 15: Bloom Fuel Cell Roof Installation

Source: Chattanooga, Tennessee's municipal utility and communications company EPB

Photovoltaic

Solar PVs use cells consisting of layers of semiconducting material to convert sunlight into electricity. Light gets absorbed within the crystal cell structure and causes individual electrons to move around the crystal freely. This movement produces an electrical current.

In this study the size of the PV array was limited by the available roof space. The maximum installed capacity per square foot was assumed to be 15W/ft^2, which is typical of PV panels installed in 2014. Higher efficiency products such as Sunpower's X21 series are also available, which can increase this power density to around 18W/ft^2. However, 15W/ft^2 is a more typical value.

The core goal of the CIRE Project is to maximize the amount of renewable energy installed in buildings. Therefore, the free roof area of each building example has been filled with PV panels to maximize the renewable generation, as summarized in Table 7.

Table 7: PV Capacity

Scale	PV Size (kW)
Convention Center	900
Single Building	700
Community	3,000

The costs for PVs used in this study are presented in Table 8. The lifetime of the PV is assumed to exceed the HOMER project lifetime of 25 years. The replacement costs can therefore be set to zero.

Table 8: PV Costs[20]

Costs		
Capital	4,600	$/kW
Replacement[21]	0	$/kW
O&M[22]	32	$/kW/year

Figure 16: Typical PV Installation on a Commercial Building

[20] Berkeley Lab, 2013

[21] No replacement of the PV modules is required for 25 years. O&M costs include inverter replacement.

[22] O&M Costs include inverter replacement

Energy Storage

In October, the CPUC approved a mandate[23] that will require California's three IUOs to add 1.3 gigawatts of energy storage to their grids by 2024. Pumped storage above 50 MW is not included in these targets. The mandate states that utilities may own no more than half of the storage assets in this target and that 200MW of customer-sited behind-the-meter storage is required. The scale of the mandate ensures that California will become the world's largest market for energy storage. The rule that only 50% of the assets can be owned by the utilities also opens the path for a growth of merchant storage, customer-owned energy assets, and other arrangements that will be a challenge to incorporate into today's utility and grid regulatory frameworks.

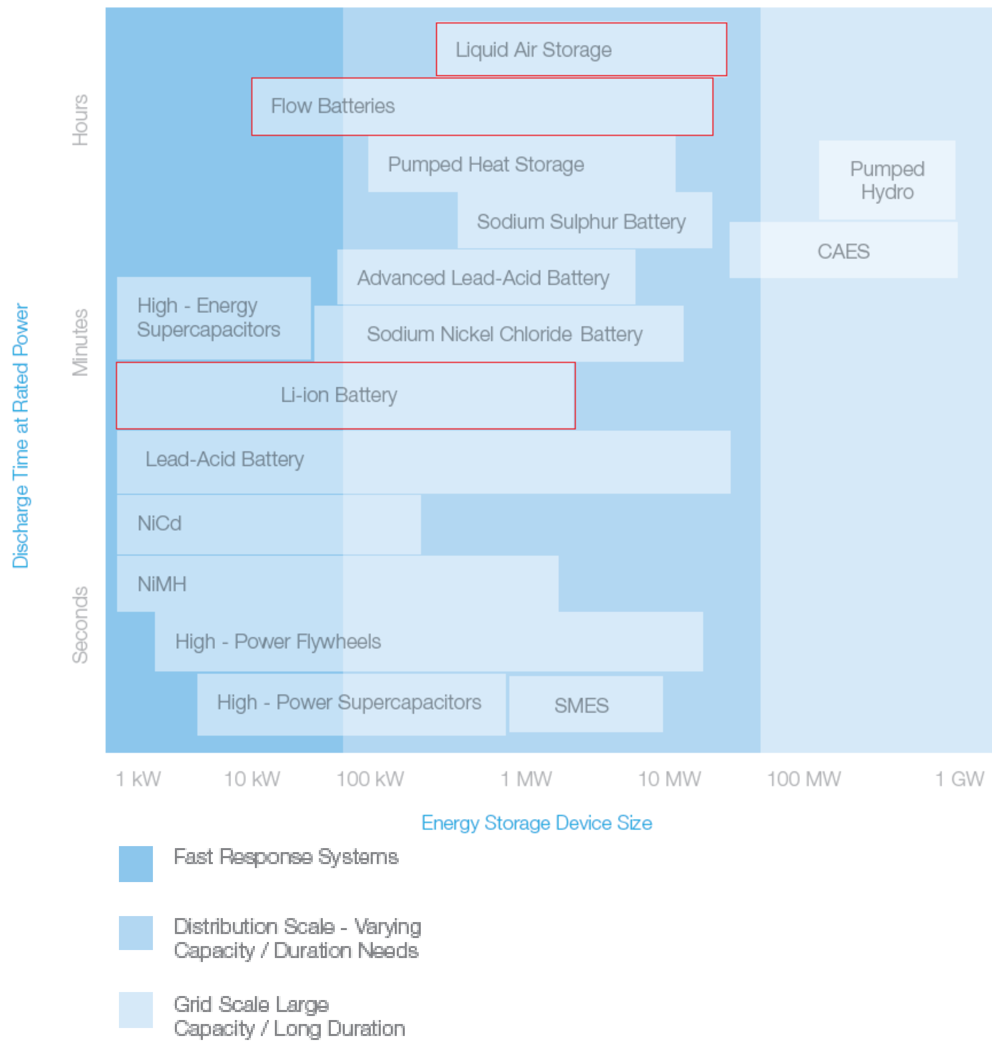
The mandate stated that the storage must be cost competitive (this may include incentives). In order to facilitate the storage business models to ensure cost competitiveness and only a 50% utility ownership model, there needs to be regulatory reform and a set of regulations to guide the development of storage technologies. Specific details pertaining to how the CPUC will regulate customer-owned storage assets, beyond existing programs like the state's Self-Generation Incentive Program, will be addressed in future rulemakings.

There are various methods of storing electricity and each technology type fills a differing storage need or application. For this project, three energy storage technologies were investigated in order to assess storage technologies that are suitable for the three building scales in this report. These are identified in Figure 15. The storage technologies assessed for this analysis are as follows:

- li-ion batteries
- liquid air energy storage (LAES)
- flow batteries

[23] See http://www.cpuc.ca.gov/PUC/energy/electric/storage.htm for further details

Figure 17: Energy Storage Application and Technology Overview



Source: Arup

Figure 17 shows differing storage technologies, with those used in this assessment highlighted in red. The storage power rating is shown in the x axis while the energy rating is shown in the y axis. There are three broad electricity storage categories:

1. Fast response systems that can charge and discharge their electricity quickly. These systems do not necessarily need to store a large amount of energy.
2. Distribution-scale storage, which has varying needs. Some applications will require fast response systems to balance an electrical grid while others require larger storage volumes discharged over hours to mitigate a peak load event.
3. Grid-scale storage, which requires a large amount of capacity and energy is not the focus of this study. This study is based on community scale systems and as such technologies suitable for grid-scale storage were not considered.

The three technologies that were chosen for this study are all suitable technologies (in terms of power and energy) for building and community storage applications and are highlighted in red in the figure. Each technology can store and discharge electricity for several hours of duration.

Lithium-Ion Batteries

Li-ion batteries are a type of rechargeable battery in which lithium ions move from the negative electrode to the positive electrode during discharge and back during charging. They are commonly used in consumer electronic products for which a high-energy density is required. The technology can be scaled up to distribution scale and is commonly used in electric vehicles.

Li-ion batteries can be used for many grid applications including the following:

- frequency regulation
- voltage regulation
- integration of renewable energy sources

Lithium barriers are very flexible and are suitable for fast response storage applications as well as bulk storage to around several MWs.

The costs for li-ion batteries used in this study are presented in Table 9.

Table 9: Lithium-Ion Battery Costs[24]

Costs		
Capital	1,390	$/kWh
Replacement[25]	1,250	$/kWh
O&M	30	$/kWh/year

The batteries can be installed outside of a building, within a building, or on the roof of a building. However, batteries are most often installed outside of the building footprint. A typical size for a 1MW/1MWh battery is approximately 20ft by 8ft. Adding in ancillary equipment and setbacks takes the space requirements for a 1MWh system to approximately 680 ft^2. Companies such as Xtreme Power can significantly shrink the footprint of containerized solutions by not utilizing shipping containers, which most manufacturers use.

[24] Arup quote from various manufacturers of batteries (grid scale 1MW/1MWh+). O&M costs include full 10-year warranty.

[25] After the end of the warranty period. Assumes that the fixed equipment such as concrete mounting pads and ancillary items make up 10% of the total capital cost.

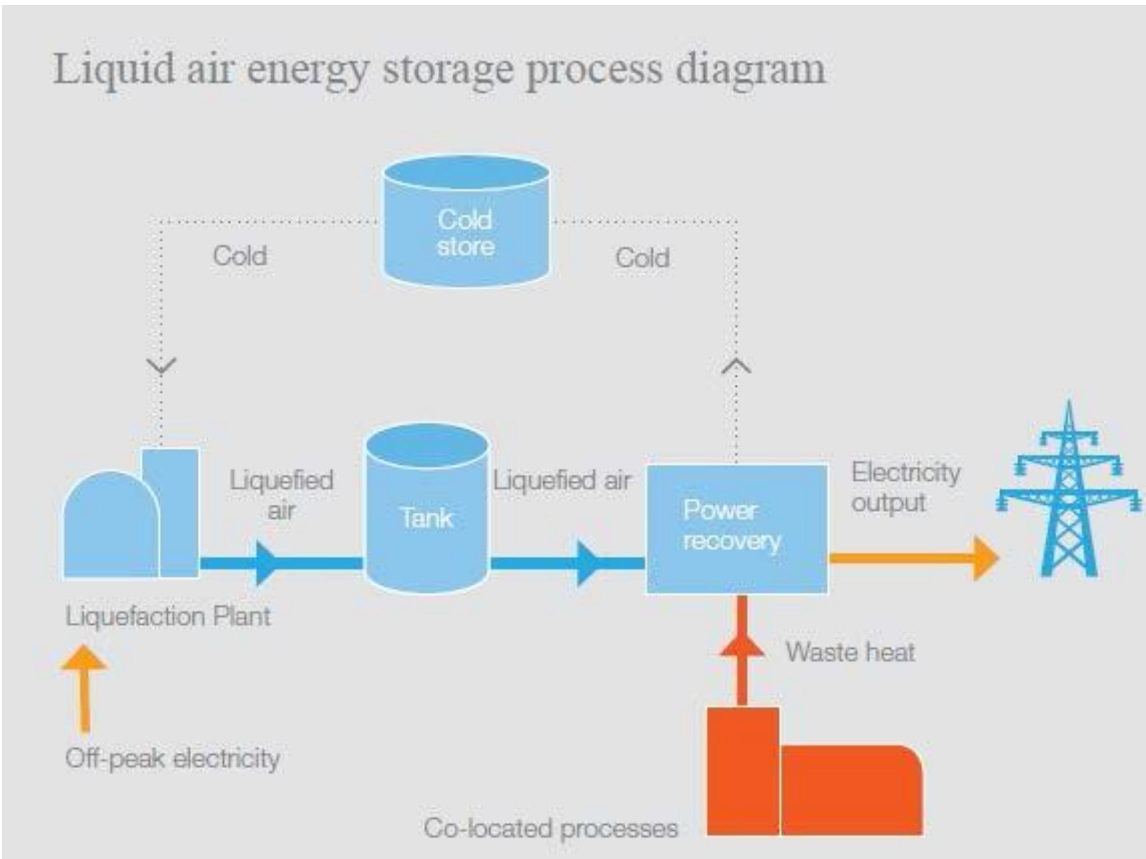
Figure 18: Typical Large-Scale Battery Installation

Source: Xtreme Power

Liquid Air Energy Storage

This energy storage technology uses liquid air or liquid nitrogen stored in insulated low-pressure tanks at cryogenic temperatures as the energy storage medium. This can either be imported to the tank by the purchase from existing supply chains or manufactured on site via a liquefaction plant. When the energy is required, the liquid air is pumped from the tank via heat exchangers to expand and drive a generating turbine.

Figure 19: LAES Process Diagram



Source: High View Power

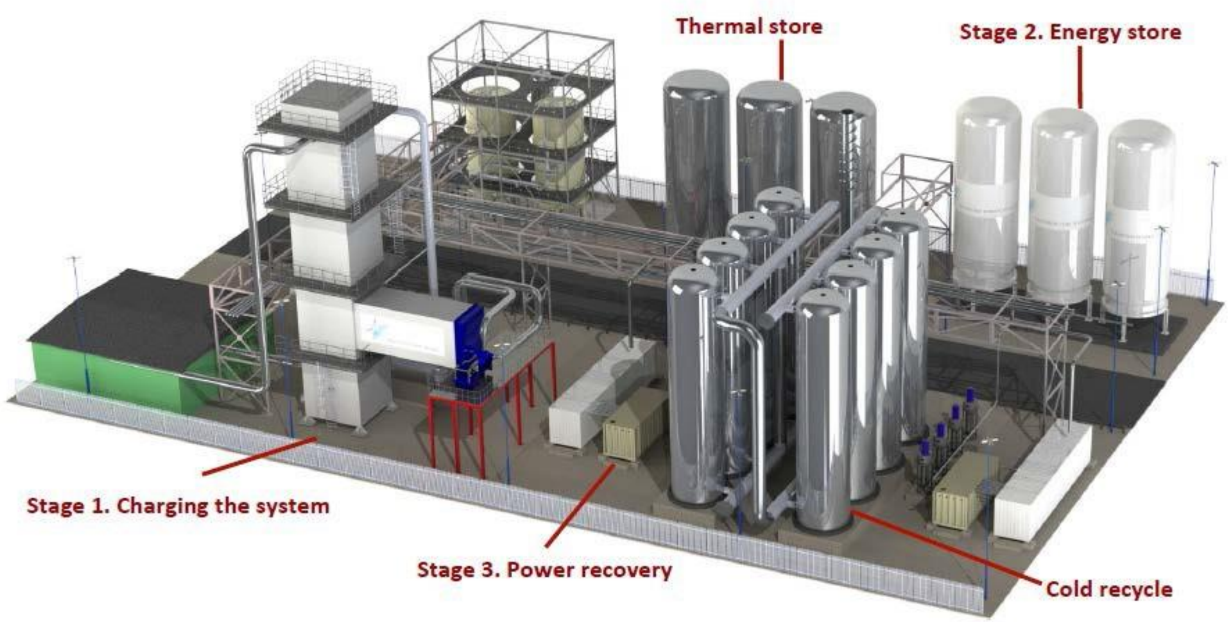
Liquid air storage can be used for many grid applications including the following:

- energy time shifting
- balancing services
- integration of renewable energy sources

Bulk energy storage is a particular strength of the LAES technology with the immediate capability for large-scale and long-duration storage. It is comparable to compressed air energy storage. Charge and discharge periods can be sized to suit the application as discharge periods of 4 to 5 hours daily are easily achievable (longer less frequent discharge periods are possible but are not the sweet spot of the technology).

Although there are limited grid-scale installations to date, one example is the 350kW, 2.5MWh installation at Slough, UK. The installation is currently operating to provide reserve power to the grid at times when traditional generation fails. The footprint of the pilot plant is approximately 5,300 ft^2. The technology manufacturer, Highview Power, was recently awarded UK Government funding to construct a large multi-MW 5MW/15MWh plant in the UK. The technology has a maximum sizing of 50MW/200MWh with equipment available in the current supply chain.

Figure 20: LAES Full-Scale Layout



Source: High View Power

The physical space-take of the technology can be reduced by purchasing liquid nitrogen and having it delivered to the site. This eliminates the requirement for on-site liquefaction (charging the system).

The costs for liquid air storage used in this study are presented in Table 10.

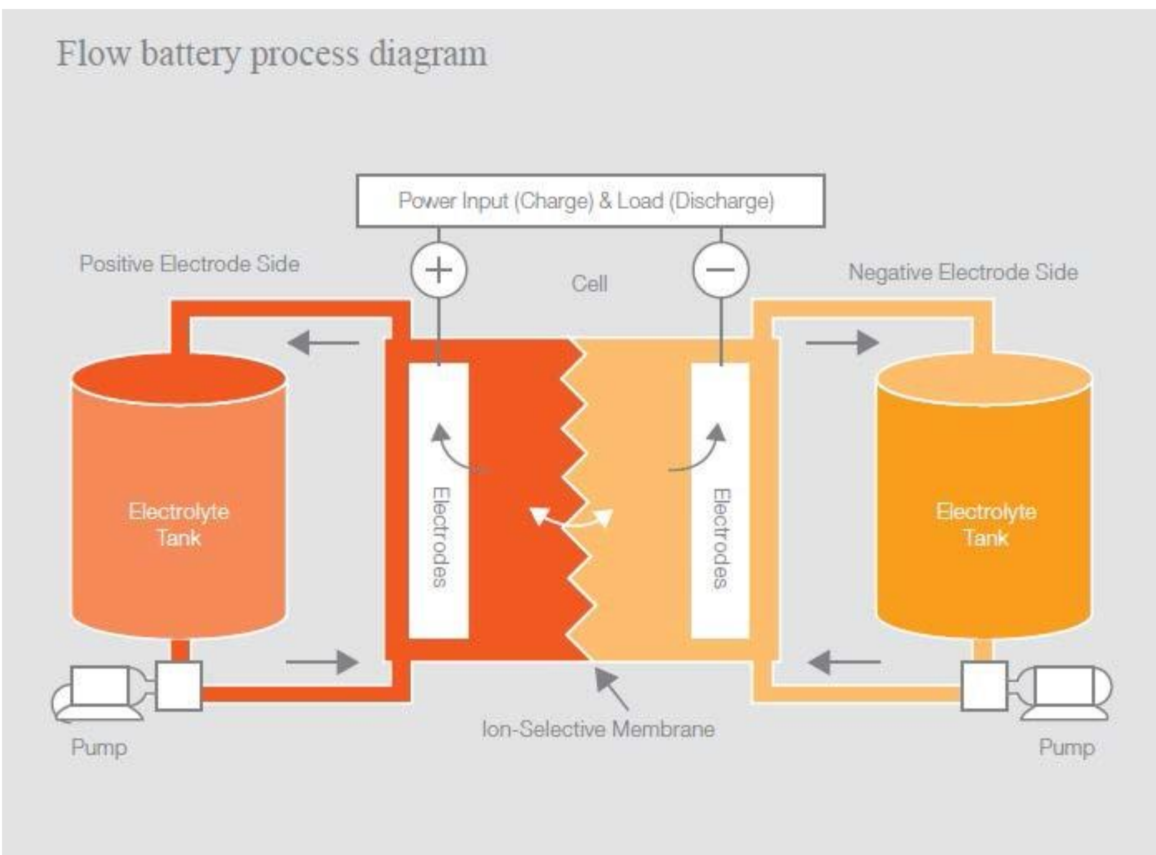
Table 10: Liquid Air Storage Costs[26]

Costs		
Capital	395	$/kWh
Replacement	316	$/kWh
O&M	9.875	$/kWh/year

Flow Batteries

Flow batteries are rechargeable batteries using two liquid electrolytes (one positively charged and one negatively) as the energy carriers. The electrolytes are separated using an ion-selective membrane which, under charging and discharging conditions, allows selected ions to pass to complete chemical reactions. The electrolytes are stored in separate tanks and are pumped into the battery when required. The storage capacity of flow batteries can be increased by simply utilizing larger storage tanks for the electrolyte.

Figure 21: Flow Battery



Source: Arup

[26] Brett G.

Flow batteries can be used for many grid applications including the following:

- load balancing
- standby power
- integration of renewable energy sources

The costs for flow batteries used in this study are presented in Table 11.

Table 11: Flow Battery Costs[27]

Costs		
Capital	956	$/kWh
Replacement	173	$/kWh
O&M	2	$/kWh/year

A 600kW, 6-hour storage device has recently been installed in California at the Gill Onions processing plant (2012). This flow battery is the largest example of a flow battery installation in the world. The scale of the flow battery installation is shown in the image below.

Figure 22: Flow Battery

Source: Prudent Energy

The approximate size of the building to house the energy storage equipment is 4,500ft^2.

Energy Storage Maximum Feasible Sizes

As identified in the previous section, the footprint of the various storage technologies varies for a given energy storage capacity. As this analysis is investigating the urban environment, the space-take of the storage is a very important aspect to consider. Land is expensive in cities and

[27] Stiel A., Skyllas-Kazacos M., 2012

towns and a development will want to maximize the development value for a given land plot. In order to understand the space-take of the various storage technologies, we have compared the area required per MWh of energy storage with a standard U.S. parking space of 300 ft^2.

Table 12: Energy Storage Space-take per MWh

Storage	Area (ft^2/MWh)	Parking Spaces (Number/ MWh)
Li-ion	680	2.3
LAES	2120	7.0
Flow battery	1250	4.2

It was assumed that all storage technologies will be installed outside of the building footprint as is typical for large-scale energy storage. Storage technologies are suitable for in-building applications at a small scale, but in order to assess the maximum scale of technologies for each of the three building scales we have assumed that the storage space-take can occupy no more than the space required by 5% of the total parking spaces. In order to mitigate the loss of 5% of the parking spaces, the developer could provide mitigation by enhancing ride-share capabilities of the development.

In San Francisco, a commercial/retail development can have a maximum of 3.3 parking spaces per 1,000ft^2, while the maximum allowable for a residential building is 1 parking space per unit or 1 space per 1,333ft^2 of residential development.[28] In San Francisco there are also some areas of the city that have lower allowances. Across California the average parking space allowances are typically higher than San Francisco. For this assessment, the parking space allowances described above for San Francisco were applied to the square footage of the three building types to calculate the number of parking spaces and the corresponding area for each scale type.

Using no more than 5% of the parking space allowance, the maximum feasible energy storage size is summarized in Table 13.

[28] The Paramount at 655 Mission Street in San Francisco has a total area of approximately 660,000 ft^2 and houses 495 apartments. Therefore there is approximately 1 residence per 1,333 ft^2 in a residential high rise building.

Table 13: Energy Storage Capacity

Scale	Number of Parking Spaces	Energy Storage Size (MWh)		
		Li-ion	LAES	Flow battery
Convention Center	115	2.4	0.8	1.4
Single Building	167	3.6	1.2	2.0
Community	620	13.6	4.4	7.4

For each scenario, a range of storage capacities from 0 to 60 MWh were studied with smaller intervals between the studied data points in the lower end of the range and larger intervals at the higher end of the range. Where HOMER calculates the size of the storage in excess of the values in the table above, we note that this result is infeasible from a space-take standpoint and then calculate the load reduction required to ensure a feasible result.

CHAPTER 6:
Ownership Models

There are a number of ownership options for the generation and storage assets that will be required to implement the resilience criteria. These models may include individual stakeholder, third-party, and community ownership. The Task 2 and Task 3a reports produced for the CIRE Project detail the various ownership options for energy assets, as well as interconnection options. The following section includes some key conclusions from those more comprehensive reports. For further information, please see the Task 2 and Task 3a reports

Convention Center and Single Building Scale

These two scales of development ownership may be fairly straightforward as each single building will have a single connection point to the utility grid. The building owner may install generation and storage behind the electricity meter and use the assets on-site, typically under a net energy metering (NEM) arrangement.

When the wider grid experiences an outage, the generation and storage assets continue to operate and the building becomes a microgrid, operating independently until the wider grid returns[29]. For the modeling work, it was assumed that the building owner owns and operates all of the generation and storage assets and that these assets are permitted to operate in the event of a grid outage.

The generation (photovoltaic [PV] and fuel cells) assets would typically be connected under a Rule 21 arrangement and operate via an NEM tariff. The interconnection may be a pure NEM arrangement (projects under 1MW in size) or a mix of NEM and non-NEM generation (projects over 1MW in size). Further details on the interconnection process can be found in the Task 2 CIRE Project report. Should the individual buildings be a multitenant building, generation that is installed at the building level is assumed to be installed by the building owner and operated under a virtual net metering tariff where the generation is credited to individual tenants. The generation assets will be "behind-the-meter" assets.

The energy storage device and the desire to operate the device in the ancillary services market present some complications. Further details on these issues and solutions are discussed in Chapter 8.

Community Scale

The community that was modeled contains a mix of residential, commercial, and retail tenants. All of the buildings are multitenant, are separated by public highways, and could in fact be developed at different times by different developers.

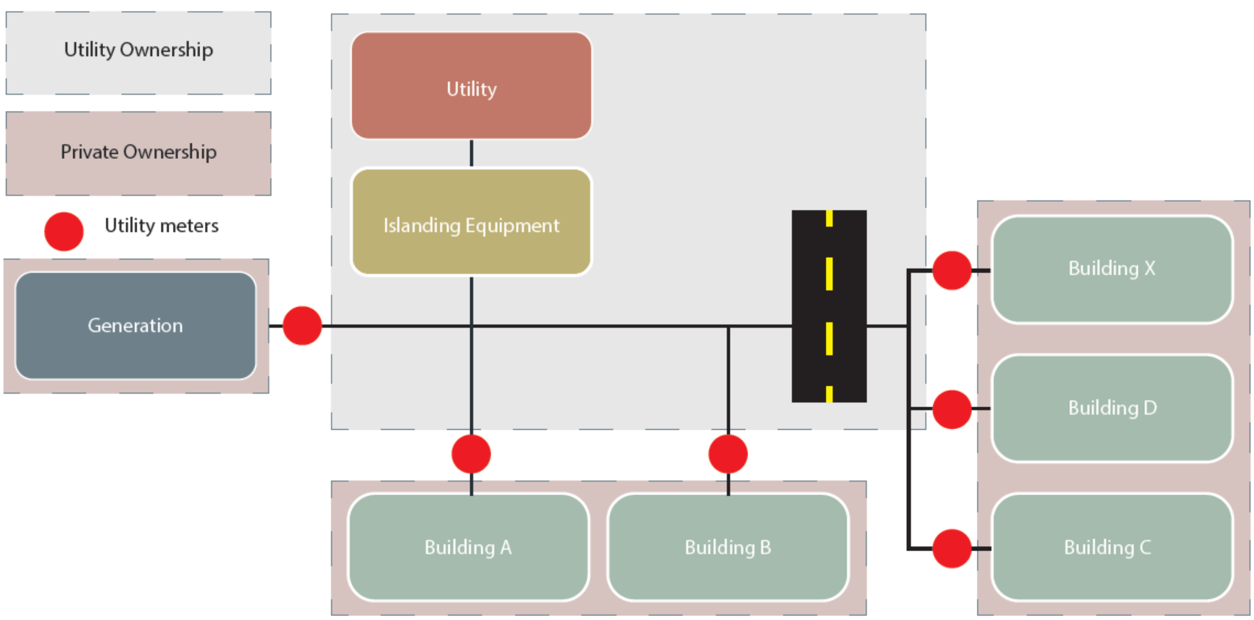
[29] Note: This will require non-standard inverters to be installed. Current regulations require that inverters do not operate in the event of a grid outage. This protection is called anti-islanding protection and discussions and technical solutions would need to be agreed with the interconnecting utility.

To make use of the roof space each building will contain PV mounted on the roofs (under 1MW individually). To meet building codes and standards each building will likely contain emergency generation in the form of diesel generators. Fuel cells and energy storage may be contained within the buildings or at the community scale to pool resources .[30]

This type of community was described in CIRE Model 4 in the Task 2 report. Within the model it is assumed that the utility owns and operates the islanding equipment. The utility may also choose to own the electricity storage asset at the substation level and allow this to provide resilience to communities during a grid outage.

Generation that is installed at the building level is assumed to be installed by the building owner and operated under a virtual net metering tariff where the generation is credited to individual tenants. The generation assets will be "behind-the-meter" assets. In a community model, the generation and storage assets are required to operate together in an outage. An enabling technology, such as a community microgrid controller, will control the assets as one in order to supply all the required power to the buildings. This community microgrid may be owned and operated by the utility or by a third party. The merits of the ownership of the controller are discussed in the Task 2 report.

Figure 23: Task 2 CIRE model 4



[30] Regulatory challenges will occur when sharing generation, as identified in the Task 2 and 3a reports.

CHAPTER 7:
Results

This chapter presents the results from the HOMER simulations. It also describes the storage capacities needed to meet the electricity demand and how the cost of energy varies with storage capacities for the studied generation and storage combinations. The results are presented in scatter plot charts, showing the cost of energy as a function of storage capacity. Only storage capacities where the system configuration can meet the electricity demand are presented.

For many of the scenarios, the storage systems are larger than what is feasible due to the spatial constraints of the buildings. Simulations with limited storage capacity (bound by the defined spatial constrains for energy storage) for each scale scenario were therefore performed in order to study how much of the load a system with the limited storage can meet. These results are presented as bar charts, showing the necessary load reduction. This load reduction could be achieved by a building manager or by an occupant initiating demand-response protocols.

As defined earlier in the report, combinations of generation technologies were modeled and HOMER varied the size of the energy storage in order to allow supply and demand to balance over the outage periods. The combinations of generation are listed below:

- PV
- diesel generator + PV
- fuel cells + PV
- diesel generator + fuel cells + PV

Convention Center Scale

The capacities for the different generation technologies used in simulations of the convention-center-scale scenario are presented in Table 14.

Table 14: Generation Capacities - Convention Center Scale

Technology	(kW)
Generator	1,000
Fuel Cell	600
PV	900

PV

The results for simulations at convention center scale using PV as the only generation are presented in Figure 24. It shows that all of the studied storage technologies are infeasible in terms of size, which indicates that fixed-generation output (for example diesel generator or fuel cells) is needed to find solutions with storage capacities below the spatial limits.

Figure 24: Storage Capacities Needed for Generation Only from PV, at Convention Center Scale

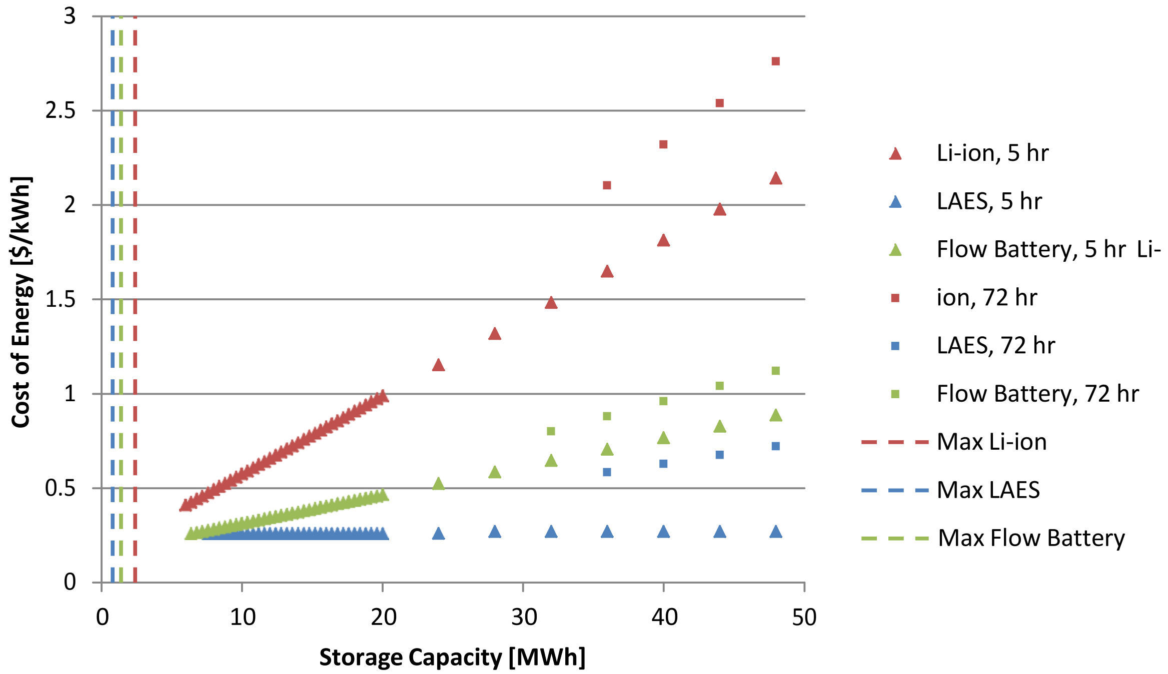
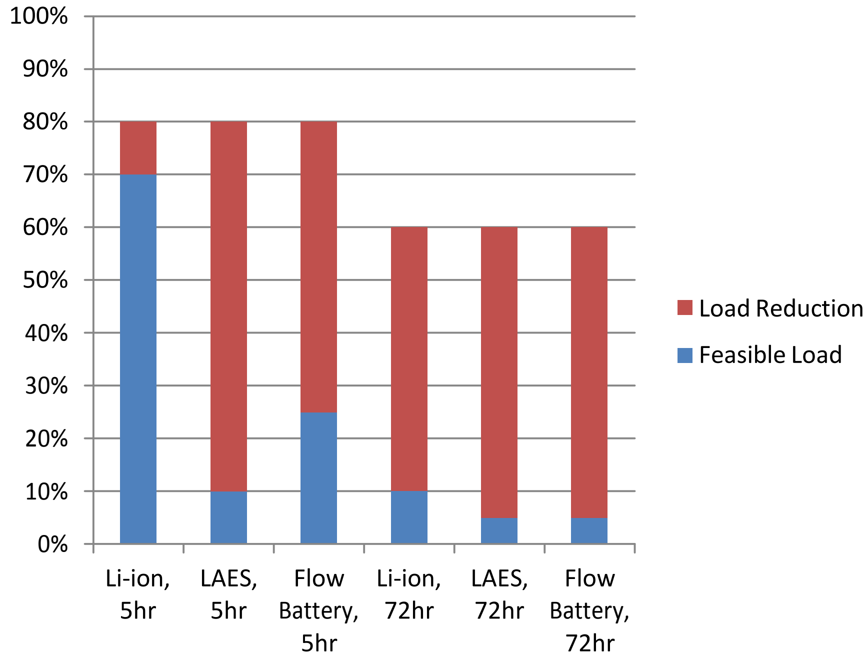


Figure 24 shows the load reduction (in percentage of full load) needed if the studied storage technologies were implemented up to their maximum allowable scale. For the 5-hour resilience scenario, li-ion batteries become feasible in terms of size if the load is reduced to 70%. This may be a tolerable reduction in contrast to the reduction needed for the LAES and flow battery. For the 72-hour resilience scenario the reductions that are needed are intolerably low.

Figure 25: Load Reductions Needed to Find Feasible Solutions for the Maximum Storage Capacities with Generation Only from PV, at Convention Center Scale



Diesel Generator + PV

The results for simulations at the convention center scale using a generation combination of diesel generator and PV are presented in Figure 26. It shows that no storage is needed for the 5-hour resilience scenario because the generator and PV can meet the entire stated building load for this period. (Note that the red, green, and blue triangles all meet at 0 MWh, even though they are merged into one green triangle in the figure).

For the 72-hour resilience scenario there are no feasible solutions when the diesel generator (with 24 hours of fuel), PV, and electricity storage are combined. As can be seen in the graph, the required sizes of storage to meet this resilience scenario are all greater than the maximum storage size that is permitted due to spatial constraints. In order to make the resilience scenario feasible, either the space-take limits must be increased or the loads that are supported in an outage reduced.

Figure 26: Storage Capacities Needed for a Generation Combination of Diesel Generator and PV, at Convention Center Scale

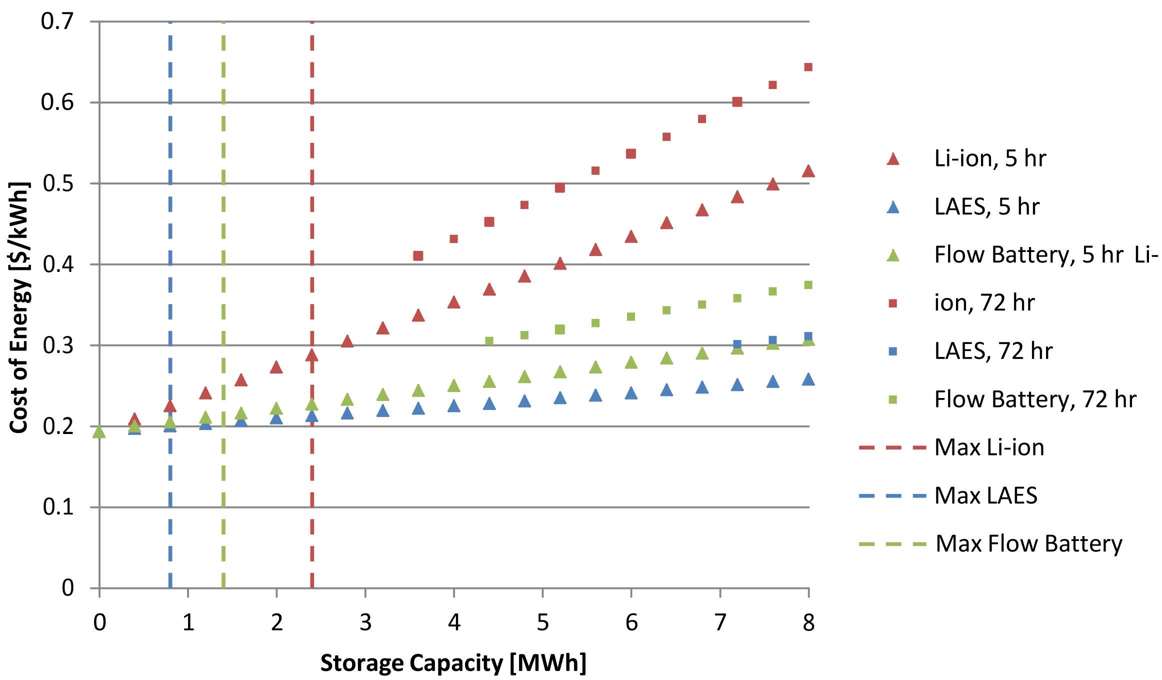
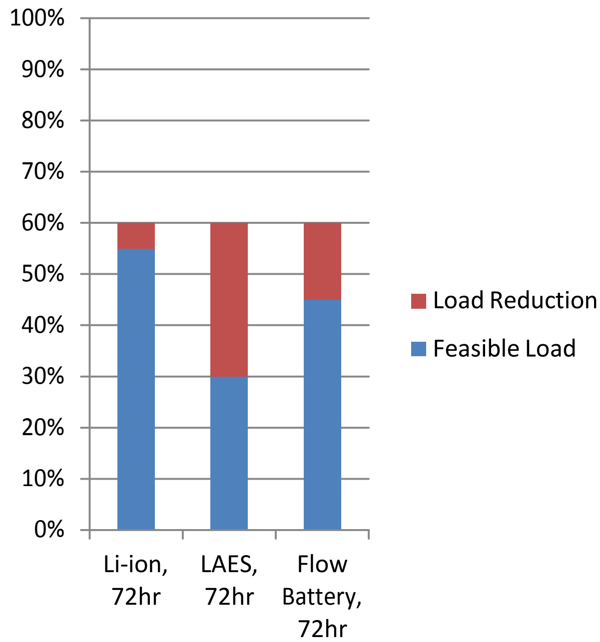


Figure 27 shows the load reduction (in percentage of full load) needed if the storage technologies in the 72-hour resilience scenario were implemented up to their maximum allowable scale. The 60% limit shows the percentage of the full load used in the simulations for the 72-hour resilience scenario. For li-ion batteries the load only needs to be reduced another 5%, down to 55%, which is most likely a tolerable reduction. For the scenario with flow batteries, the load needs to be reduced down to 45% and for systems with LAES down to 30%.

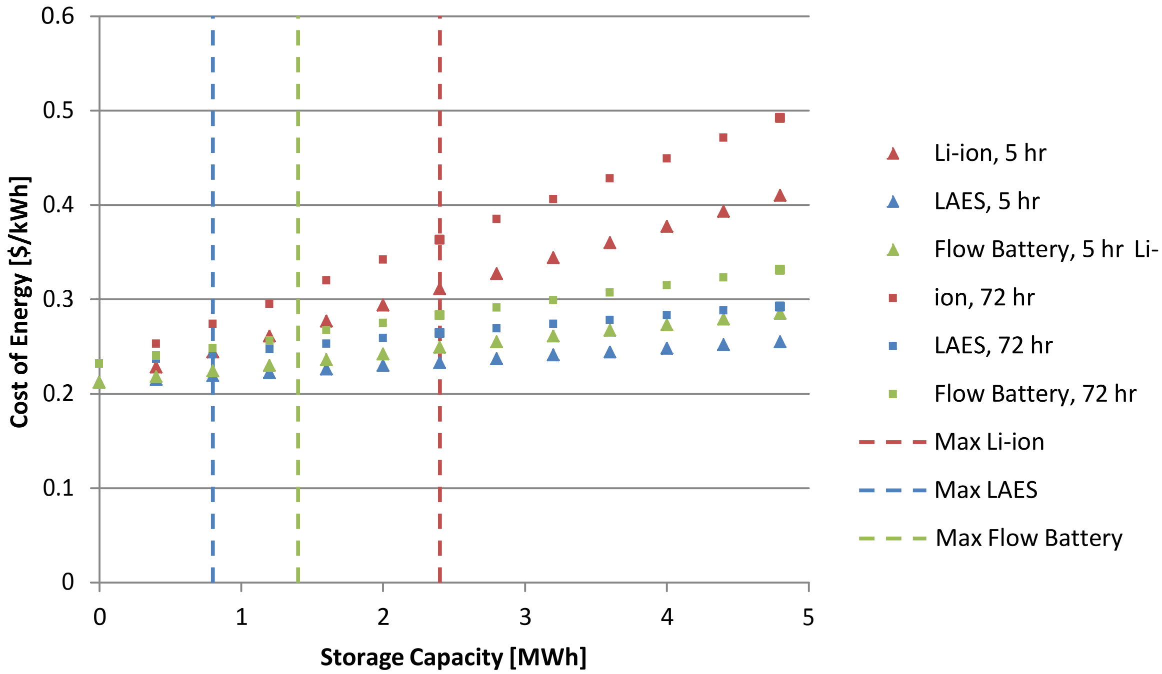
Figure 27: Load Reductions Needed to Find Feasible Solutions for the Maximum Storage Capacities with a Generation Combination of Diesel Generator and PV, at Convention Center Scale



Fuel Cells + PV

The results for simulations at the convention center scale using a generation combination of fuel cells and PV are presented in Figure 28**.** It shows that the generation in fuel cells and PV are enough to meet the load, even without any storage. This can be explained by the large fuel cell capacity, which is due to the large base load of the convention center. However, HOMER does not model the second by second variation in PV output or the load balancing of the convention center. Fuel cells are base-load technologies and do not like to vary their output. Without electricity storage, there will be significant energy imbalances between supply and demand. While storage may not be required on an hourly energy consumption basis, it will be required to make this scenario operate in a real world example. Storage is excellent at ensuring the stability of microgrids, as the examples that we are studying demonstrate.

Figure 28: Storage Capacities Needed for a Generation Combination of Fuel Cells and PV, at Convention Center Scale

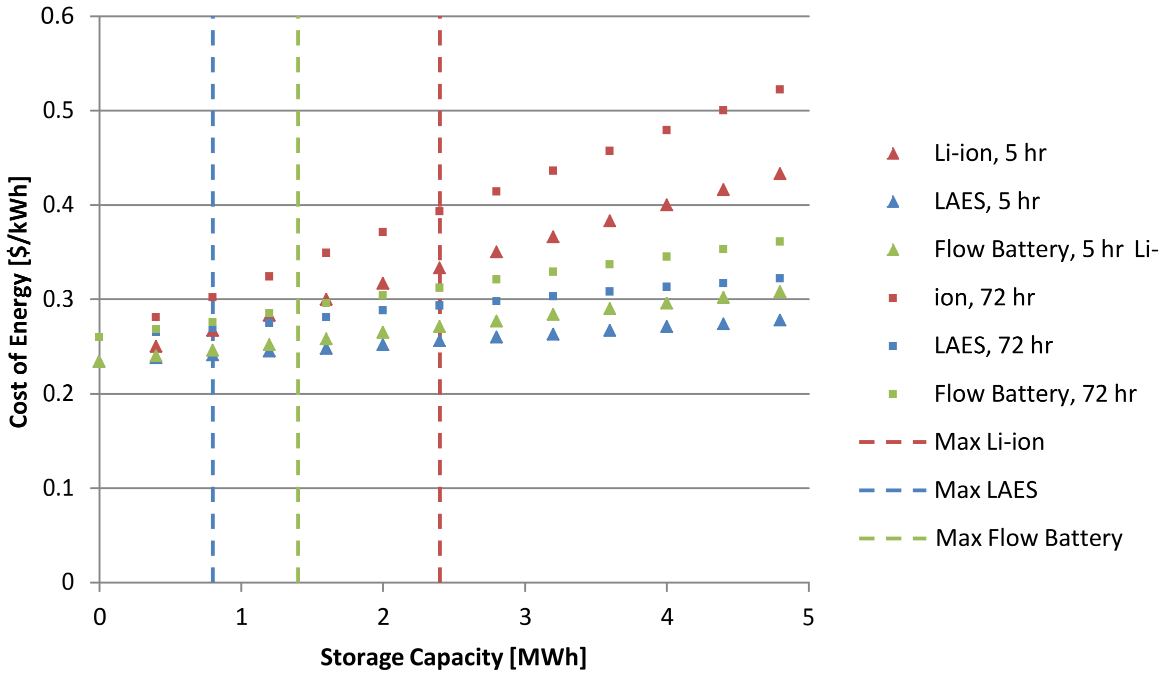


Diesel Generator + Fuel Cells + PV

The results for simulations at the convention center scale using a generation combination of diesel generator, fuel cells, and PV are presented in Figure 29**.** It shows that there is no need for any storage. However, the comments made in the previous section on the requisite energy for system stability also apply to this scenario.

Compared to the results in Figure 26, the cost of energy is higher for this scenario. Since generation from fuel cells and PV can meet the load (even without any storage), adding a diesel generator leads to too much installed generation capacity and thereby unnecessary costs.

Figure 29: Storage Capacities Needed for a Generation Combination of Diesel Generator, Fuel Cells and PV, at Convention Center Scale



Summary Convention Center Scale

During a 5-hour power outage, the optimal scenario, in terms of size and cost, is a generation mix from diesel generator and PV without any storage. With the exception of the PV only scenario, all scenarios are feasible and do not require electricity storage capacity to be implemented. This is due to the small duration of the outage and the ability of the fixed generation to provide the majority of the load with PV, allowing less diesel/gas to be consumed. However, HOMER does not take into account other functions that energy storage can provide and there are energy markets that the storage can access that are not part of the HOMER calculation. These are discussed in Chapter 8. What HOMER does not model is the short-term fluctuations in the supply of electricity and demand. PV energy can vary significantly minute by minute. Diesel generators can load follow for this 5-hour period and balance this supply and demand. However, the fuel cells are not designed to load follow and it is very likely that electricity storage would be necessary to manage a 5-hour outage where diesel generation is not provided.

During a 72-hour power outage, the optimal scenario, in terms of size and cost, is a generation mix from fuel cells and PV without any storage. Again, in practical terms, energy storage will be required to provide the stability between energy generation and demand. Adding energy storage does not significantly increase the cost of the energy during the outage. The scenarios with a limited supply of diesel (24 hours) and PV are not feasible. The energy storage required for these scenarios is larger than the footprint criteria we have stated in this document. Making these scenarios feasible would require an increased footprint for electricity storage and/or a reduction in the loads that can be supplied for this length of outage. For the generation scenarios that include fuel cells in this assessment, HOMER has calculated that energy storage is not required on an economic basis. As previously stated, detailed electrical modeling of a microgrid would likely require the implementation of energy storage.

Table 15: Convention Center Scale Summary

Generation Scenario	Storage Technology	5 Hour	72 Hour
Diesel Generator + PV	Li-ion	✓	X
	LAES	✓	X
	Flow Battery	✓	X
PV	Li-ion	X	X
	LAES	X	X
	Flow Battery	X	X
Fuel Cells + PV	Li-ion	✓	✓
	LAES	✓	✓
	Flow Battery	✓	✓
Diesel Generator + Fuel Cells + PV	Li-ion	✓	✓
	LAES	✓	✓
	Flow Battery	✓	✓

Single Building Scale

The capacities for the different generation technologies used in simulations of the single-building scale scenario are presented in Table 16.

Table 16: Generation Capacities - Single Building Scale

Technology	(kW)
Generator	1,000
Fuel Cell	60
PV	700

PV

The results for the simulations at single building scale using PV as the only generation are presented in Figure 30. It shows that all of the studied storage technologies are infeasible in terms of size, which indicates that fixed-generation output (for example diesel generator or fuel cells) is necessary in order to find solutions with storage capacities below the spatial limits.

Figure 30: Storage Capacities Needed for Generation Only from of PV, at Single Building Scale

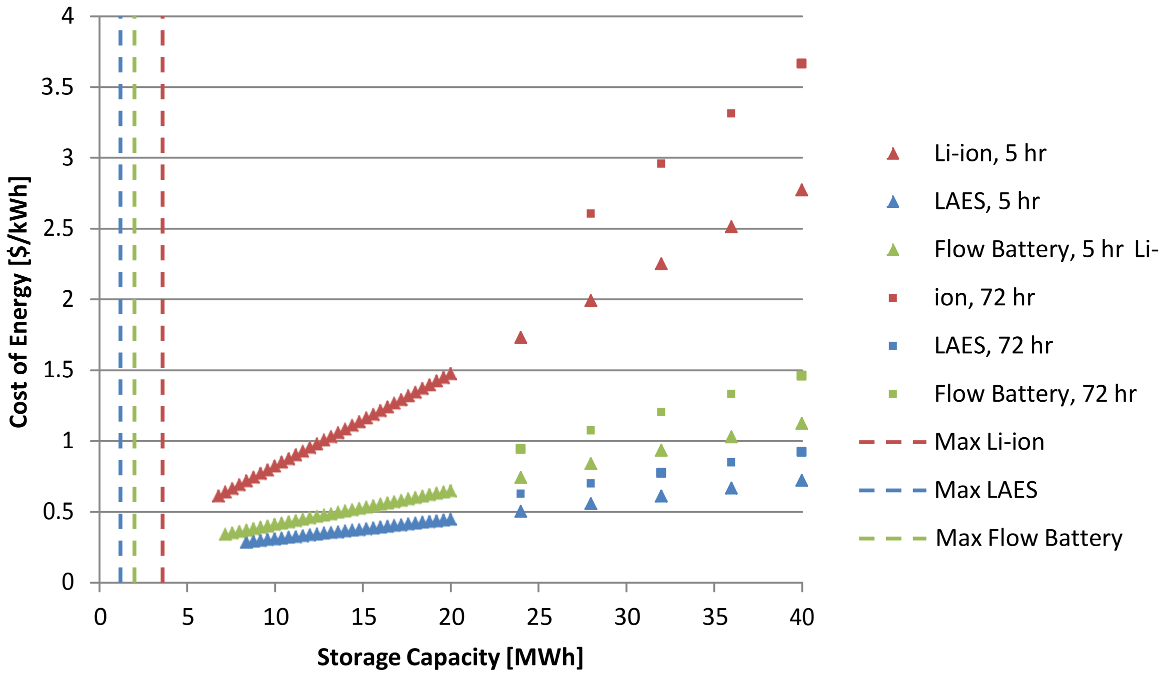
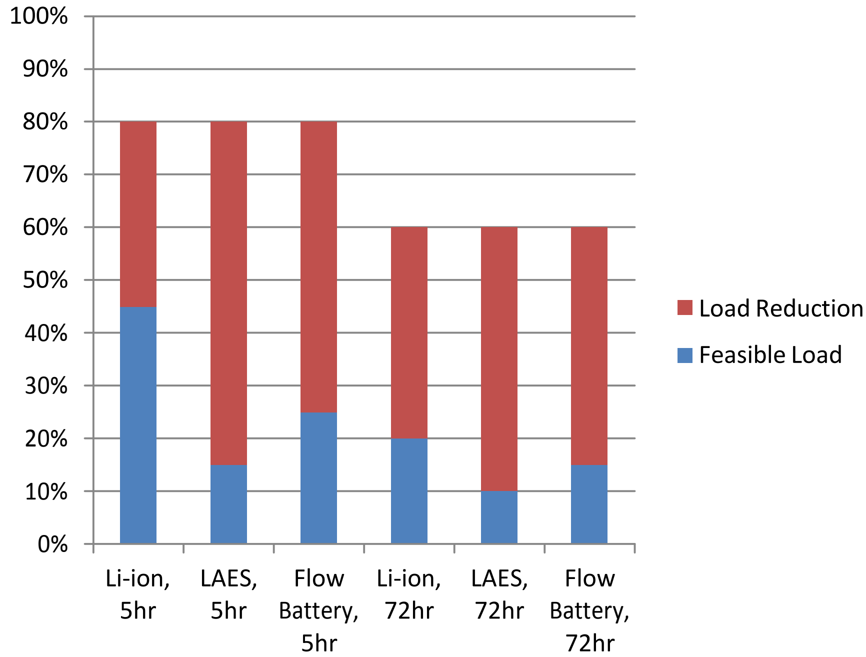


Figure 31 shows the necessary load reduction (in percentage of full load) if the studied storage technologies were implemented up to their maximum allowable scale. For the 5-hour resilience scenario, li-ion batteries become feasible in terms of size if the load is reduced to 45%. This may be a tolerable reduction, in contrast to the reductions needed for LAES and flow batteries. For the 72-hour resilience scenario, the necessary reductions are intolerably low.

Figure 31: Load Reductions Needed to Find Feasible Solutions for the Maximum Storage Capacities with Generation from PV only, at Single Building Scale

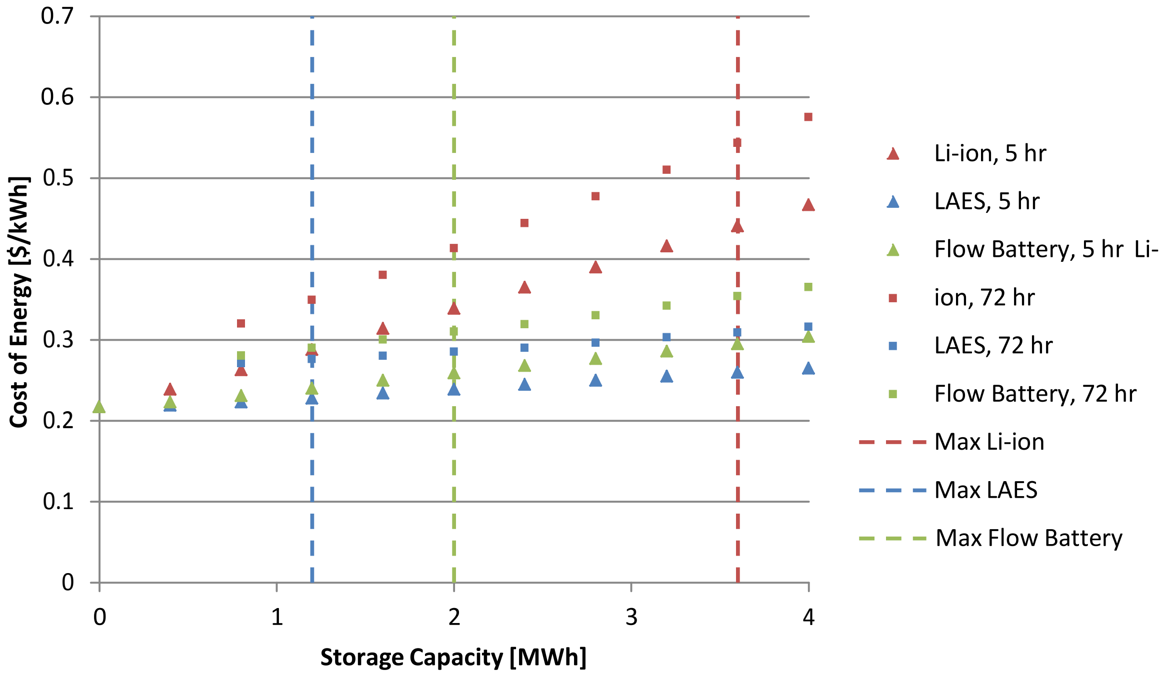


Diesel Generator + PV

The results for simulations at the single building scale using a generation combination of diesel generator and PV are presented in Figure 32**.** It shows that no storage is needed for the 5-hour resilience scenario because the generator and PV can meet the entire stated building load for this period. (Note that the red, green, and blue triangles all meet at 0 MWh, even though they are merged into one green triangle in the figure).

For the 72-hour resilience scenario, all of the storage technologies are feasible in terms of size. Again, it is obvious that li-ion batteries are the most expensive of the studied storage options and that LAES is the cheapest.

Figure 32: Storage Capacities Needed for a Generation Combination of Diesel Generator and PV, at Single Building Scale



Fuel Cells + PV

The results for simulations at the single building scale using a generation combination of fuel cells and PV are presented in Figure 33. It shows that all of the studied storage technologies are infeasible in terms of size. This can be explained by the small fuel cell capacity, which stems from the small base load of the single building.

Figure 33: Storage Capacities Needed for a Generation Combination of Fuel Cells and PV, at Single Building Scale

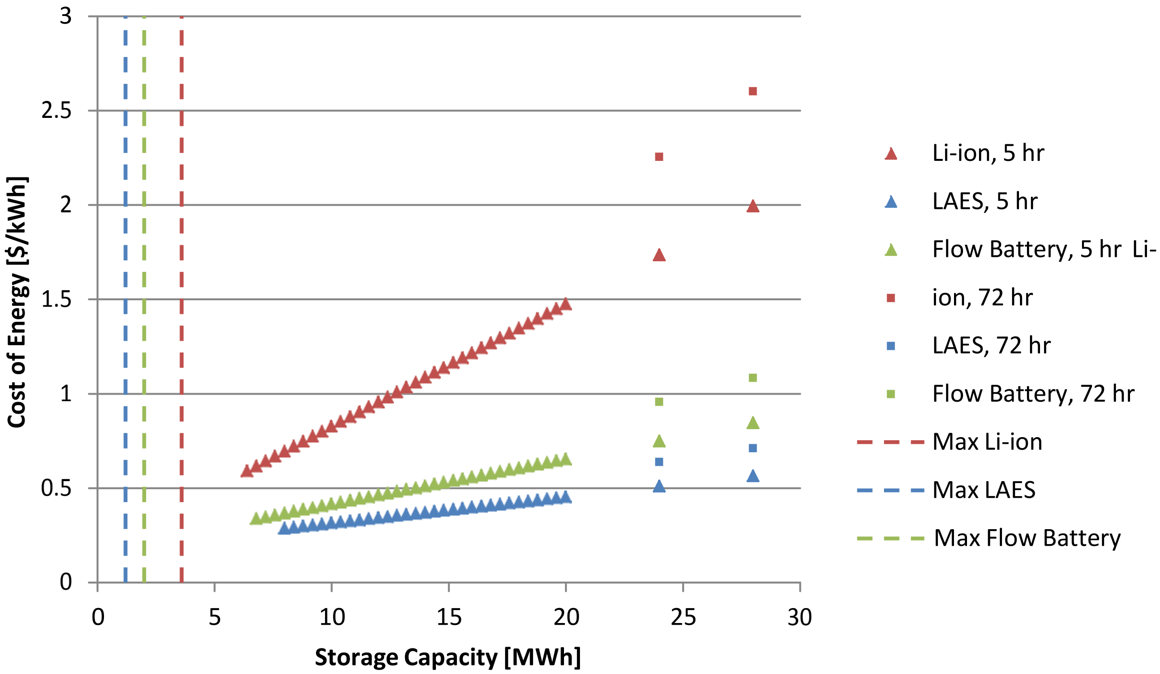
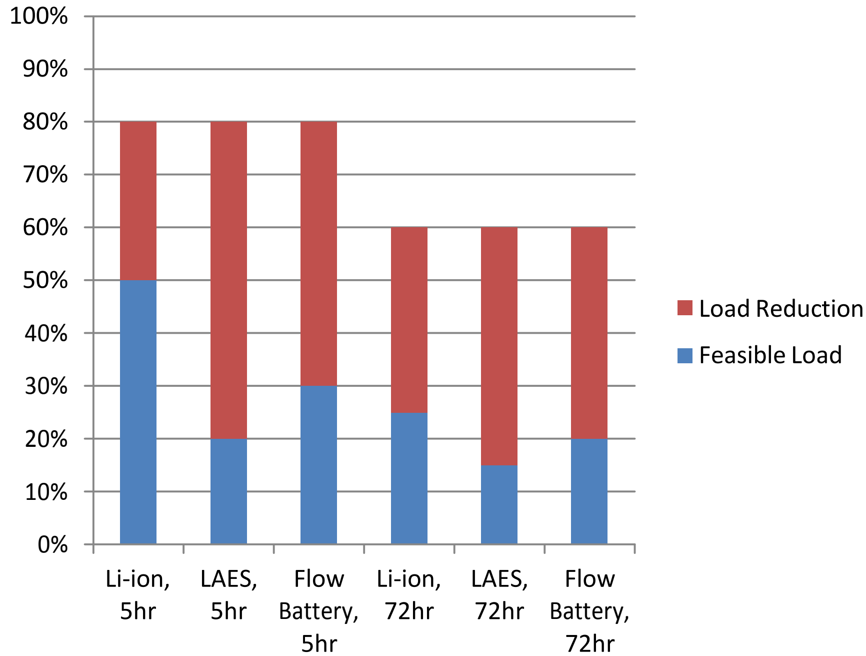


Figure 34 shows the necessary load reduction (in percentage of full load) if the studied storage technologies were implemented up to their maximum allowable scale. For the 5-hour resilience scenario, li-ion batteries become feasible in terms of size if the load is reduced to 50%. This may be a tolerable reduction, in contrast to the reductions needed for LAES and flow batteries. For the 72-hour resilience scenario, the necessary reductions are intolerably low.

The result of this generation combination of fuel cells and PV is very similar to the results for the scenario with PV as the only generation. This indicates that a larger, fixed-output generation, in addition to the 60 kW of fuel cells, is necessary in order to find solutions with storage capacities below the spatial limits.

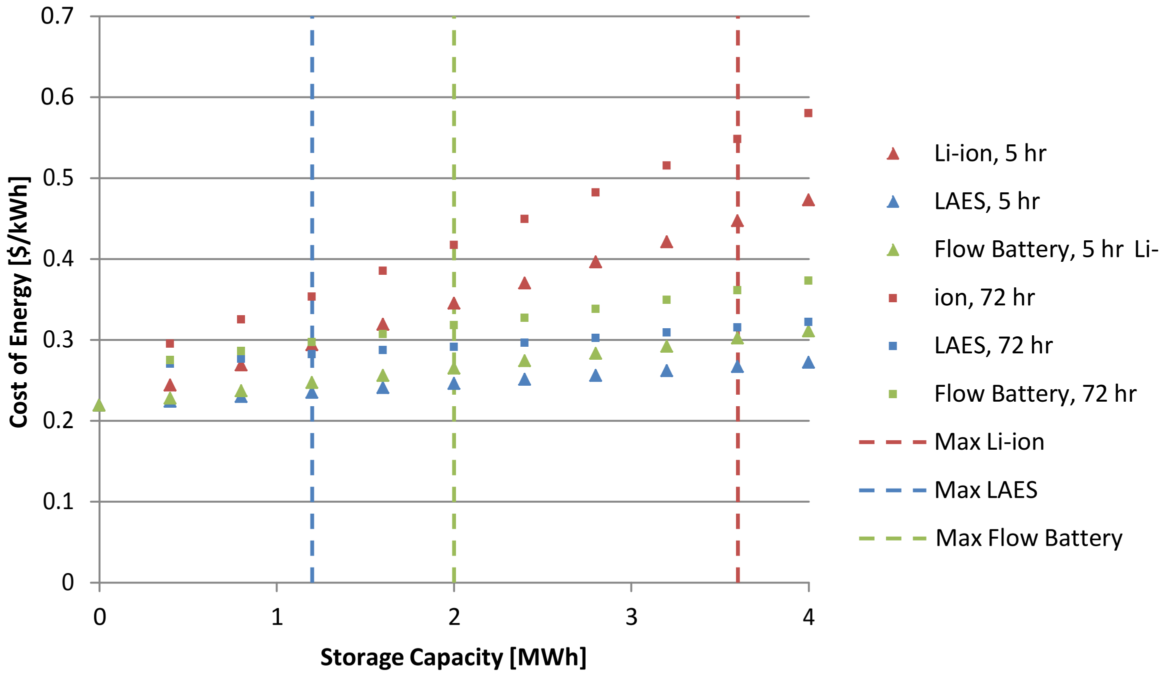
Figure 34: Load Reductions Needed to Find Feasible Solutions for the Maximum Storage Capacities with a Generation Combination of Fuel Cells and PV, at Single Building Scale



Diesel Generator + Fuel Cells + PV

The results for simulations at the single building scale using a generation combination of diesel generator, fuel cells, and PV are presented in Figure 35. Just as for the scenario with diesel generator and PV, there is no need for any storage for the 5-hour resilience scenario. For the 72-hour resilience scenario, all of the storage technologies are feasible in terms of size with the cost of the technology being the differentiator.

Figure 35: Storage Capacities Needed for a Generation Combination of Diesel Generator, Fuel Cells and PV, at Single Building Scale



Summary Single Building Scale

During a 5-hour power outage, the optimal scenario, in terms of size and cost, is a generation mix from diesel generation and PV without any storage. All scenarios including a diesel generator are feasible and do not require electricity storage capacity to be implemented. This is due to the small duration of the outage and the ability of the fixed generation to provide the majority of the load with PV allowing less diesel/gas to be consumed. However, HOMER does not take into account other functions that energy storage can provide. There are also energy markets that the storage can access that are not part of the HOMER calculation. These are discussed in Chapter 8.

During a 72-hour power outage, the optimal scenario is a generation mix from all of the three studied generation technologies with a small amount of electricity storage.

The reason why the scenarios with a combination of fuel cells and PV cannot meet the load is because the fuel cell capacity is too low at the single building scale. The energy storage required for these scenarios is larger than the footprint criteria we have stated in this document. To make these scenarios feasible, it would require an increased footprint for electricity storage and/or a reduction in the loads that can be supplied for this length of outage.

Table 17: Single Building Summary

Generation Scenario	Storage Technology	5 Hour	72 Hour
Diesel Generator + PV	Li-ion	✓	✓
	LAES	✓	✓
	Flow Battery	✓	✓
PV	Li-ion	X	X
	LAES	X	X
	Flow Battery	X	X
Fuel Cells + PV	Li-ion	X	X
	LAES	X	X
	Flow Battery	X	X
Diesel Generator + Fuel Cells + PV	Li-ion	✓	✓
	LAES	✓	✓
	Flow Battery	✓	✓

Community Scale

The capacities of the different generation technologies used in simulations of the community-scale scenario are presented in Table 18.

Table 18: Generation Capacities – Community Scale

Technology	(kW)
Generator	2,750
Fuel Cell	250
PV	3,000

PV

The results for the simulations at the community scale using PV as the only generation are presented in Figure 36. It shows that during a 5-hour power outage, only the li-ion is feasible in terms of size. During a 72-hour power outage, none of the studied storage technologies are feasible.

Figure 36: Storage Capacities Needed for Generation Only from PV, at Community Scale

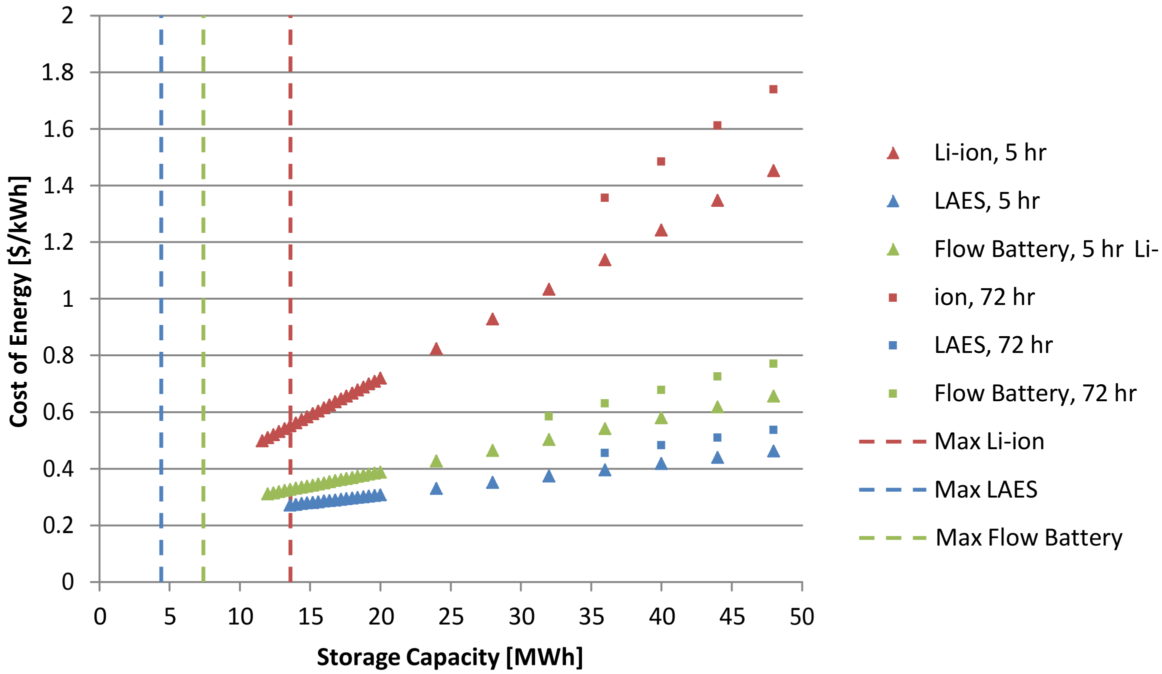
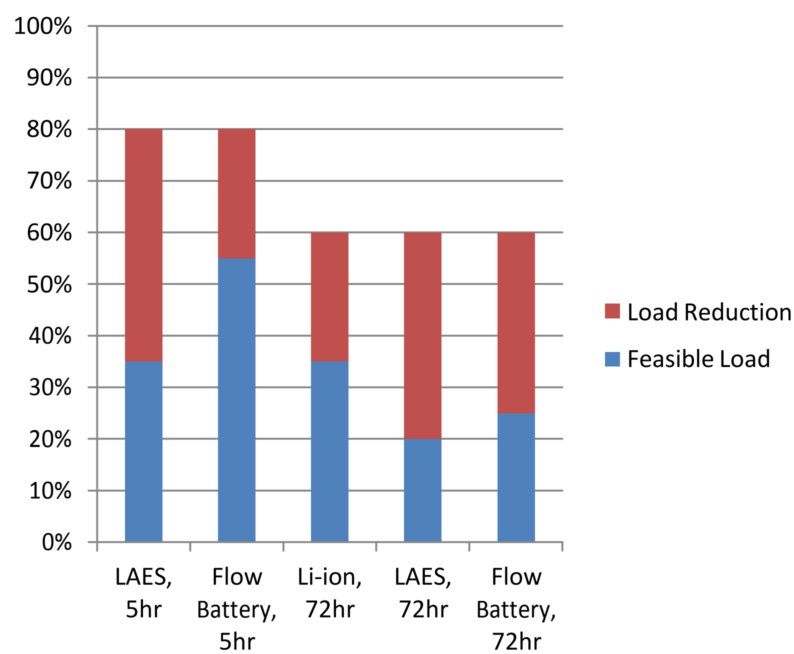


Figure 37 shows the necessary load reduction (in percentage of full load) if the studied storage technologies were implemented up to their maximum allowable scale. For the 5-hour resilience scenario flow batteries become feasible if the load is reduced to 55%. For the rest of the scenarios, greater reductions are necessary.

Figure 37: Load Reductions Needed to Find Feasible Solutions for the Maximum Storage Capacities with Generation from PV only, at Community Scale

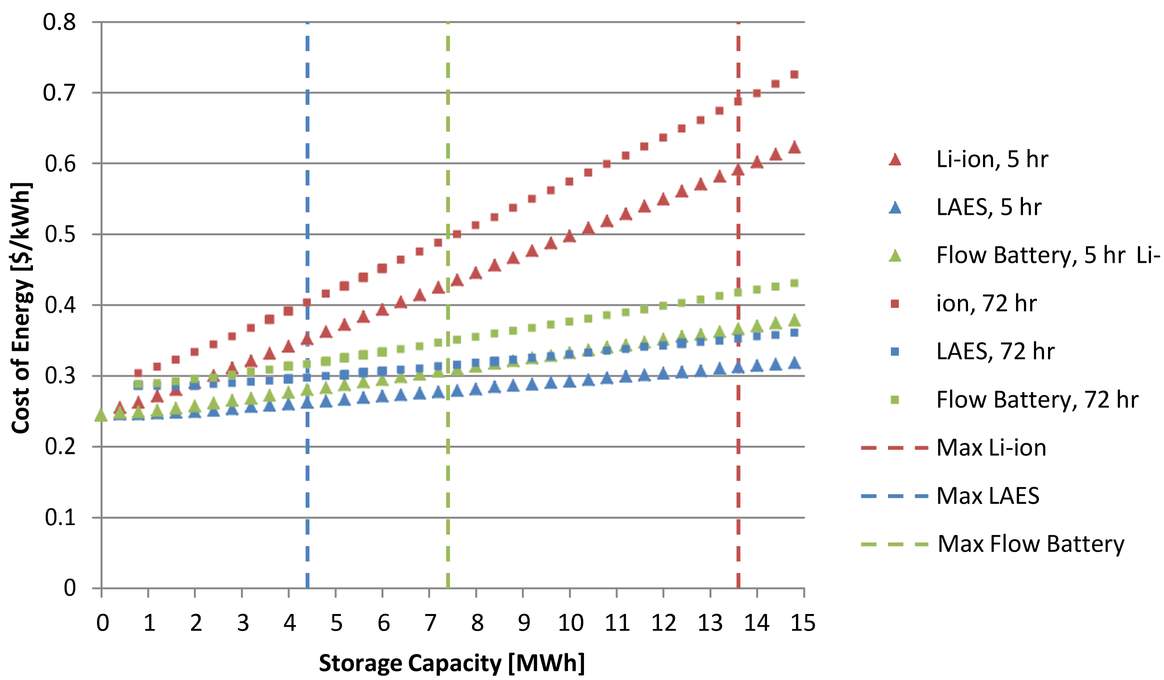


Diesel Generator + PV

The results for the simulations at the community scale using a generation combination of diesel generation and PV are presented in Figure 38. It shows that no storage is necessary for the 5-hour resilience scenario. The generator and PV can meet the entire stated building load for this period. (Note that the red, green and blue triangles all meet at 0 MWh, even though they are merged into one green triangle in the figure).

For the 72-hour resilience scenario, all of the storage technologies are feasible in terms of size. Again, it is obvious that li-ion batteries are the most expensive of the studied storage options while LAES is the cheapest.

Figure 38: Storage Capacities Needed for a Generation Combination of Diesel Generator and PV, at Community Scale



Fuel Cells + PV

The results for simulations at the community scale using a generation combination of fuel cells and PV are presented in Figure 39. It shows that during a 5-hour power outage, only the li-ion is feasible in terms of size. During a 72-hour power outage, none of the studied storage technologies are feasible. This indicates that a larger fixed-power output is needed to find solutions with storage systems below the spatial limits. Since the base load of the community is very low, the fuel cell capacity is as well.

Figure 39: Storage Capacities Needed for a Generation Combination of Fuel Cells and PV, at Community Scale

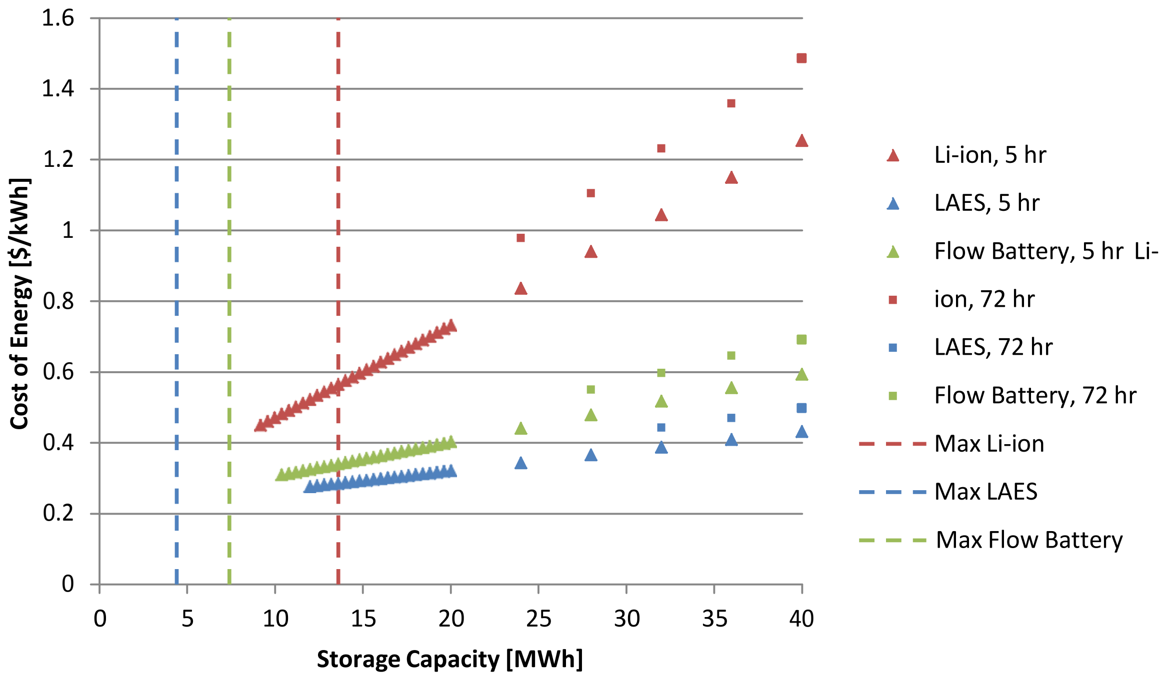
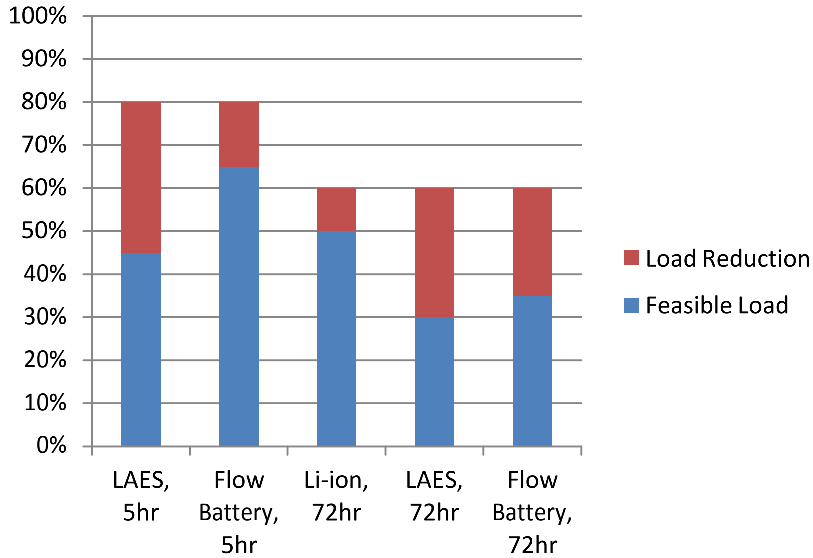


Figure 40 shows load reduction (in percentage of full load) needed if the studied storage technologies were implemented up to their maximum allowable scale. For the 5-hour resilience scenario, flow batteries become feasible in terms of size if the load is reduced to 65%. For LAES the load has to be reduced more, to 45%. Such reductions may be tolerable. For the 72-hour resilience scenario the load needs to be reduced to 50% for the li-ion to become feasible, and even more reduced for the LAES and the flow battery to become feasible.

Figure 40: Load Reductions Needed to Find Feasible Solutions for the Maximum Storage Capacities with a Generation Combination of Fuel Cells and PV, at Community Scale

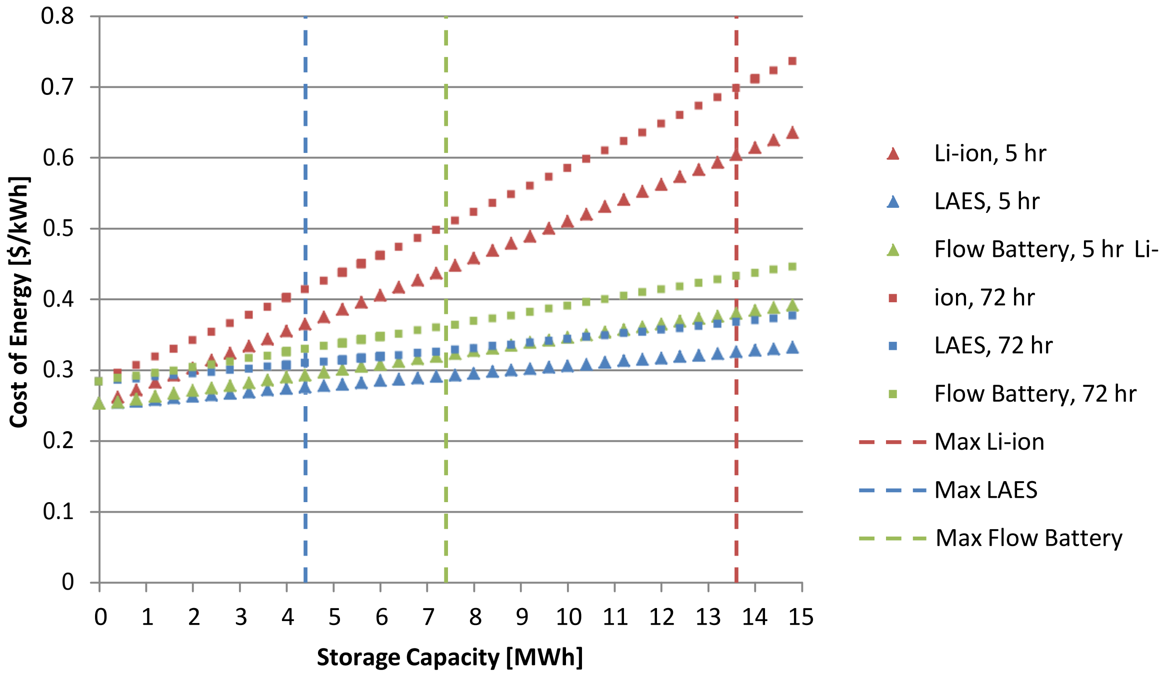


Diesel Generator + Fuel Cells + PV

The results for simulations at the community scale using a generation combination of diesel generation, fuel cells, and PV are presented in Figure 41. It shows that there is no need for any storage for any of the scenarios.

Compared to the results of the scenario with only diesel generation and PV for the 72-hour resilience, it is notable that without fuel cells, some storage is necessary. It is also important to note that the latter-mentioned scenario is the more expensive of the two.

Figure 41: Storage Capacities Needed for a Generation Combination of Diesel Generator, Fuel Cells and PV, at Community Scale



Summary Community Scale

During a 5-hour power outage, the optimal scenario, in terms of size and cost, is a generation mix from diesel generation and PV without any storage. With the exception of the scenarios with LAES and flow battery for the PV-only and fuel cells plus PV scenarios, all scenarios are feasible. Scenarios with li-ion batteries are more often feasible in terms of size because of the high efficiency of li-ion and the smaller amount of space required.

During a 72-hour power outage, the optimal scenario, in terms of size and cost, is a generation mix from all of the three studied generation technologies without any storage. All scenarios that include a diesel generator are feasible. Scenarios with a generation mix of all of the technologies do not require the implementation of electricity storage capacity. Scenarios with a combination of fuel cells and PV are not feasible because the fuel cell capacity is too low at the community scale. The energy storage required for these scenarios is larger than the footprint criteria we have stated in this document. Making these scenarios feasible would require an increased footprint for electricity storage and/or a reduction in the loads that can be supplied for this length of outage.

Table 19: Community Scale Summary

Generation Scenario	Storage Technology	5 Hour	72 Hour
Diesel Generator + PV	Li-ion	✓	✓
	LAES	✓	✓
	Flow Battery	✓	✓
PV	Li-ion	✓	X
	LAES	X	X
	Flow Battery	X	X
Fuel Cells + PV	Li-ion	✓	X
	LAES	X	X
	Flow Battery	X	X
Diesel Generator + Fuel Cells + PV	Li-ion	✓	✓
	LAES	✓	✓
	Flow Battery	✓	✓

All of the results are summarized in Appendix C.

CHAPTER 8:
Economic Analysis

In this section, simple economic analysis is presented on the various individual components that make up the modeled scenarios. The HOMER results include a generation mix of different combinations of generation and storage technologies.

An economic analysis for diesel generators has not been presented. The diesel generators in this report are required (by California Electrical Codes[31]) and were sized for life safety loads and as such will form part of the building costs. At the time of writing this report, fuel cells produced by the major manufacturers are not rated for life safety and therefore cannot be installed in place of diesel generators. This may change in the future. If manufacturers were to produce fuel cells that are rated for life systems, there is the possibility (subject to fuel storage) that diesel generators could be omitted from a life safety system.

For PV, a simple cost of electricity was referenced (over a 25 year asset life) and compared to the typical cost of grid energy to determine if PV-produced electricity is comparable to grid electricity.

For fuel cells, a simple cost of electricity was calculated (over a 10 year asset life) and compared to the typical cost of grid energy to determine if fuel cell-produced electricity is comparable to grid electricity.

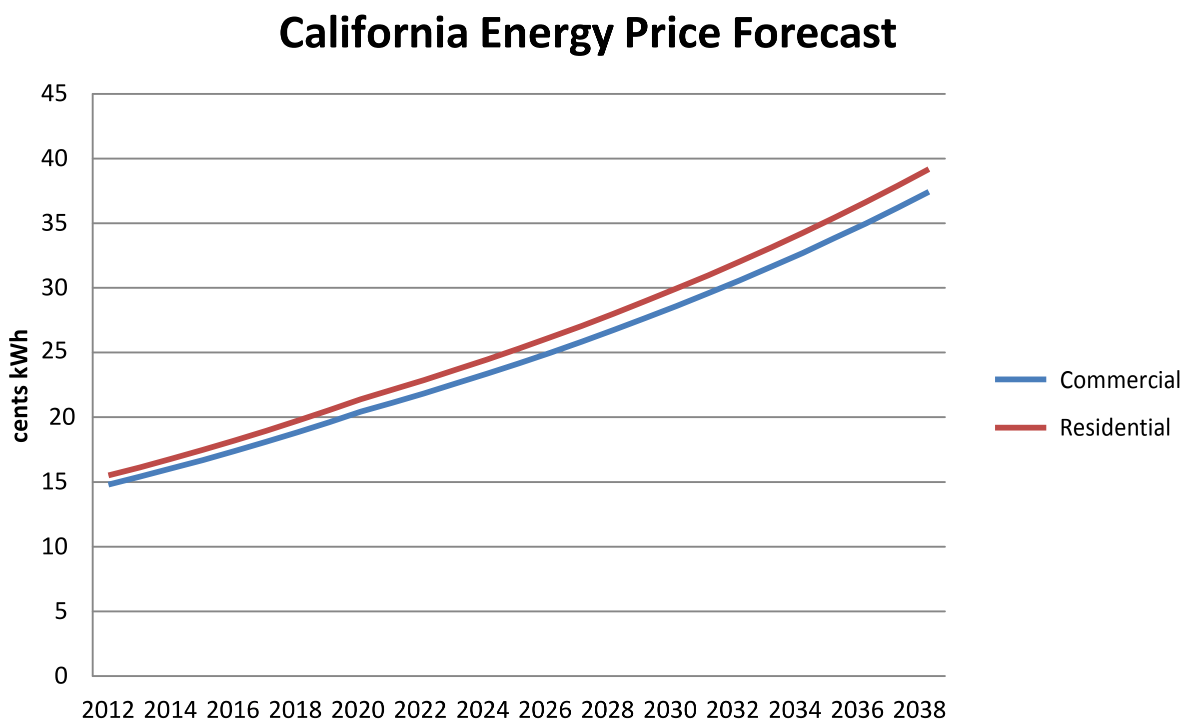
Energy storage takes a more complex approach. Energy storage is not utilized like conventional generation to lower the use of grid electricity. Energy storage in the modeled scenarios allows the systems to operate independently of the grid. However, energy storage is expensive to operate even for the rare times that grid power is not available. Therefore, ancillary service markets and their economic impact are explored in order to estimate the business case for energy storage.

Grid Electricity Benchmark

In order to determine if a particular technology is cost-effective, the price at which the generation technology can produce electricity must be compared to the price at which electricity can be purchased from the local utility. If the price at which the generation technology produces electricity is higher than the utility-purchased energy over the lifetime of the asset, then the generation technology is not cost competitive. Figure 42 shows the expected price rise of electricity over time in California.

[31] For the high rise examples we have presented, there will be significant life safety loads such as fans and pumps which are not suitable for life safety battery supply. Smaller buildings may have their life safety systems powered by batteries / inverters only.

Figure 42: California Energy Price Forecast



Source: California Energy Commission[32]

Photovoltaic

Significant work was undertaken throughout the U.S. to understand the business case for PV installations on buildings. A recent report issued by the California Energy Commission (CEC)[32] was leveraged and compared to the results from the HOMER analysis in this study.

The CEC study considered the following scenarios:

- Scenario 1: PV installed on existing buildings
- Scenario 2: PV installed on new construction buildings at a lower cost

Analysis was carried out in the years 2014, 2017, and 2020. 2017 is an important year to analyze as the tax credits for PV installations reduce from 30% to 10%[33]. Analysis was carried out for all Californian climate zones.

The studies produced the following results for the Average Customer Cost-Effectiveness.

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[32] (Mahone, 2013)

[33] 10% is an assumed value. This figure has not been calculated to date.

Table 20: Rooftop PV Cost Benefit Summary

PV Cost Scenario	Consumer Type	2014	2017	2020
More expensive	Residential (<10kW PV system)	Sometimes. Cost-effective in all climate zones except zone 1.	No. Not cost-effective in most climate zones.	Sometimes. Cost-effective in all climate zones except zone 1.
	Small commercial (<10kW PV system)	Sometimes. Marginally cost-effective, depending on climate zone.	No. Not cost-effective in most climate zones. zones	Sometimes. Cost-effective in all climate except zone 1.
	Large commercial (10-100kW PV system)	Sometimes. Cost-effective in all climate zones except zone 1.	Sometimes. Cost-effective in all climate zones except zone 1.	Yes. Cost-effective in all climate zones.
Less expensive	Residential (<10kW PV system)	Yes. Cost-effective in all climate zones.	Yes. Cost-effective in all climate zones.	Yes. Cost-effective in all climate zones.
	Small commercial (<10kW PV system)	Yes. Cost-effective in all climate zones.	Yes. Cost-effective in all climate zones.	Yes. Cost-effective in all climate zones.
	Large commercial (10-100kW PV system)	Yes. Cost-effective in all climate zones.	Yes. Cost-effective in all climate zones.	Yes. Cost-effective in all climate zones.

Source: California Energy Commission[34]

As shown in the CEC report, PV cost-effectiveness varies with the installed cost of PV, the size of the installed PV, and the loads that PV offsets. Community scale (100kW +) PV, as discussed in this report, has many advantages over smaller systems. The systems are larger and have economies of scale that offset a large amount of customers' demands and electricity consumption. For the studies we have considered, all of the systems will be 100kW and above.

Therefore, at the community scale, PV could be cost-effective in many climate zones in California. Community-scale PV, which is integrated into multitenant buildings, could be installed by the building owner or a third party and installed under a virtual net metering arrangement as described in detail in the Task 3a report. For a single-owner building such as the convention center, the standard net metering tariffs are most likely utilized.

[34] (Mahone, 2013)

As an example of the cost-effectiveness of the community-scale solution, the Moscone example is provided in Table 21.

Table 21: Moscone West Cost-Effectiveness Example

Parameter	Units	Result
System Size	kW	900
System Life	Years	25
Annual Building Electrical Load	kWh	6,435,315
Total Installation Cost of PV	$	4,140,000.00
Tax Credit	30%	-1,242,000.00
Net System Installation Cost	$	2,898,000.00
PV Maintenance	$/kW/yr	32.00
25 Year Cost of Electricity without PV	$	41,246,467.03
Total Lifetime cost of PV system	$	3,618,000.00
PV Generation Total	kWh	31,148,046
Cumulative Savings	$	7,123,783.77
PV Cost/kWh	$	0.116

The cost of the generated electricity in 2014 is $0.116, compared to approximately $0.160 from Figure 42. Therefore, at today's rates, this solar installation is cost-effective. This does not take into account the rising rate of electricity, which would further improve the cost-effectiveness.

Fuel Cells

In order for a fuel cell to be considered, a renewable source of energy biogas must be used as the fuel. In urban environments such as buildings, biogas is not captured. The only method in which biogas is feasible to use in fuel cells in urban environments is via directed biogas. Directed biogas is biogas that is produced, cleaned, and injected into a natural gas pipeline where it is commingled with natural gas. The gas is then delivered by the existing natural gas infrastructure for use at a distant facility where it will be used to power the fuel cells. Biogas is available in limited quantity in California and as such, the use of directed biogas comes at a premium of around 30% additional costs over standard natural gas.

For this assessment, we have compared natural gas and directed biogas as the fuel used in a fuel cell application.

This example is based on a modular fuel cell of 200kWe that only provides electricity as a useable output. This will have a full retail value of approximately $7/W or $1.4m.

A fuel cell in California is eligible for two incentives currently.

The first is the Investment Tax Credit (ITC) which is available through 2016 and is equal to 30% of the fuel cell installation capital cost, up to $3,000/kW, associated with business purchase of qualifying fuel cell products. If associated with a residential purchase, the ITC is equal to 30% of capital cost, up to $1,000/kW for single occupancy homes, and up to $3,334/kW for double occupancy homes.

In addition, the Self-Generation Incentive Program (SGIP) in California applies to both renewable and nonrenewable technologies. The incentive is available through December 2015[35] and it is currently not known if this program will be extended. There are two incentive levels for fuel cells. An incentive of $1.83/W for fuel cells operating on natural gas and $3.45/W for fuel cells operating on biogas (including directed) of which a maximum of 60% of the project costs qualify for the saving.

The table below summarizes a cost-effectiveness calculation for the Moscone Center using a 600kW fuel cell array (3 x 200kW fuel cells) operating on natural gas and on directed biogas.

[35] At the time of writing this report (June 2014) it is expected that the SGIP program will be extended until at least 2019.

Table 22: Fuel Cell Cost Calculation

2014 Fuel Cell Simple Payback	Natural Gas
Electrical Load (kWh)	6435315
System size (kW)	600
Fuel Cell Cost ($)	4200000
Federal Tax Incentive (30%)	-1260000
California SGIP (1$.83/W)	-1098000
Subsidized Fuel Cell Cost	1842000
Fuel Consumption (MMBtu/hr)	3.96
Natural Gas Cost ($/MMBtu)	7
Cost of Fuel per kWh generated	0.048631579
Cost of grid electricty ($/kWh)	0.160415603
Annual Cost Saving over 10 year life	$5,445,668.35
Annual Maintenance Cost ($/kWh)	0.035
25 Year C ost of Electricity without PV	$12,400,418.90
Total Lifetime cot of PV system	$6,017,892.00
PV Generation	49,932,000
Cumalative Savings	$5,445,668.35
PV Cost/kWh	$0.121

The cost of generated electricity in 2014 is $0.121, compared to approximately $0.160 from Figure 42. This cost of electricity falls further should a biogas fuel cell be considered for the project. Therefore, at today's rates, this fuel cell installation is cost-effective. This does not take into account the rising rate of electricity. This positive economic case, however, is dependent upon fuel cell subsidies which face uncertainty in the coming year.

Energy Storage

The business case for energy storage is complex and depends of many variables such as who owns the storage, what the storage is used for, and the markets that the storage device has access to.

This section describes some of the functions that energy storage can perform, the incentives that are currently available to storage, and also the leverages of the work performed in two recent energy storage studies to comment on the business cases for storage.

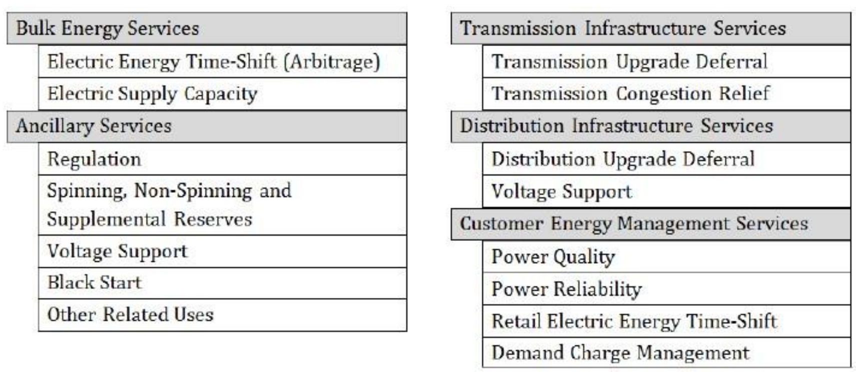
This section was written in reference to stationary energy storage.

Energy Storage Markets

Energy storage is a unique asset in the electricity market as it can act as both a generator (export energy) and a load (consume energy). Because of its unique character, electricity storage is able to operate in many electrical markets. The more markets that a storage device can operate in, the more revenue streams can be captured, all of which assists in the business case for the storage asset.

Figure 43 details some of the markets that energy storage can participate in. Each one of these markets has a separate value.

Figure 43: Electricity Storage Potential Markets



Source: EPRI

Energy storage in California is eligible for two current incentives.

The SGIP applies to both renewable and non-renewable technologies. The incentive is available through 2015 (see previous footnote) and it is currently not known if this program will be extended. An incentive of $1.62/W is available for advanced energy storage applications, of which a maximum of 60% of the project costs qualify for the savings.

The ITC is available through 2016 and is equal to 30% of the capital cost of a project. The ITC is only available to energy storage if it is procured as part of a larger system with eligible technologies such as PV and/or fuel cells. In order to meet the ITC criteria, the energy storage device must be charged with a minimum of 75% electricity from eligible renewable technologies.

Interconnection

In order for a storage device to participate in ancillary services markets, the energy storage device must have a Wholesale Distribution Access Tariff (WDAT). This wholesale interconnection is very different from the more commonly known Rule 21 retail interconnection that most CIRE projects are likely to use.

For more information on the WDAT and generator interconnection process, please see the Task 2 report for the CIRE Project.

A typical retail customer will purchase electricity from their provider under a retail tariff (commercial or residential). The retail customer will be metered with a retail meter and interconnected to the grid under a retail interconnection agreement, such as the Rule 21 interconnection agreement. Should a retail customer, such as a large commercial customer, wish to site energy storage on their site for use cases such as demand charge management, microgrid enablement, and ancillary services there are complications. The commercial customers' electricity service will likely be provided under a retail tariff. In order for the storage device to operate in the ancillary services market and earn revenue from this market, a WDAT connection is needed. There is currently no clear framework for establishing a wholesale interconnection behind a retail meter[36].

Economic Analysis

As stated earlier, there is no simple business case analysis for energy storage. The case depends on many factors such as the markets that can be accessed, the operating regime of the device, and the technology used.

Most of the economic analysis that has been carried out to date relates to battery energy storage and this is discussed in the remainder of this section.

Battery energy storage (stationary), such as li-ion, typically costs $1,390/kWh to install in California as stated in earlier sections of this report. A study by the Electric Power Research Institute (EPRI)[37] has stated that for utility-owned storage systems[38], the ability to operate in ancillary services market, particularly the regulation market, will be the primary revenue source for the storage device. However, the study concluded that in order for there to be a business case for utility-owned energy storage (free of any subsidy), the cost of energy storage would have to fall to $500/kWh (a 65% reduction from current costs).

[36] Arup are working on this very issue with a California IOU on a current project and have reached an agreement where a WDAT connection has been secured behind a retail Rule 21 meter.

[37] (Cutter & Raster, 2011)

[38] Note a utility would be able to claim the SGIP incentive and therefore makes storage economics more difficult

Energy storage is also likely to decrease in cost. Researchers at EPRI anticipate that production costs of Li-ion could be reduced significantly in the near future, due to the scale of global production of Li-ion batteries for electric vehicles. A casing example of this is the planned Tesla Giga factory, which is expected to be operational by 2020 and reduce the cost of li-ion technologies in vehicles by 30%.

A second EPRI report has further categorized three use cases for energy storage[39]. The three use cases considered are bulk transmission level storage, storage operating in the ancillary services market, and storage operating at the substation level. Each of the studies utilized EPRI's Estimation Energy Storage Valuation Tool (ESVT). The EPRI evaluation assumes that projects are installed in 2020 and that stationery storage costs have fallen to $500/kWh.

The third use case in the EPRI report, storage operating at the substation level, is particularly relevant to review from a CIRE standpoint. In the community model investigated within this report, it was assumed that the islanding equipment was owned and operated by the utility and placed at the substation supplying the community. This would also be a suitable location for utility ownership of storage consistent with the EPRI use case.[40]

In this use case, the storage system will provide system capacity and ancillary services while also being reserved for shaving substation peak load so as to help defer the investment on the substation[41]. So in this particular example, the storage device is able to claim revenue from all of these assets. This stack of revenue streams will not be available in all applications and this highlights the case-by-case assessment that is required for energy storage.

The results from the use case are shown in Figure 44.[42]

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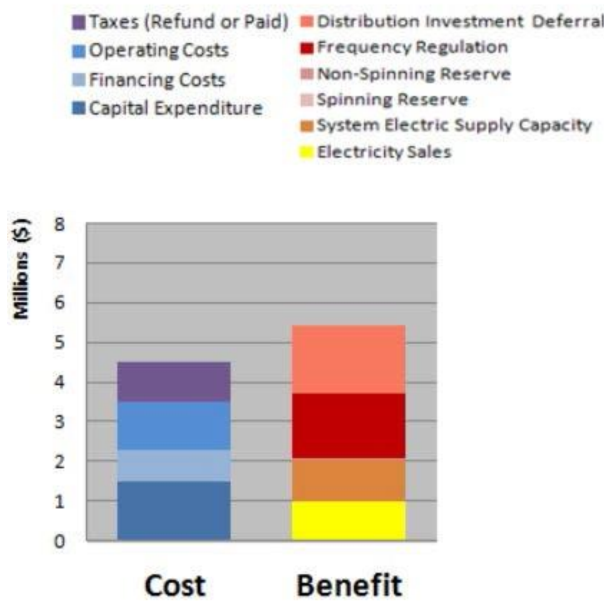
[39] (Kaun & Chen, 2013)

[40] There are many other ownership models and use cases that are feasible for energy storage.

[41] This use case depends on the substation to which the storage is connected being overloaded for certain times of the year without the storage. The use of the storage allows the utility to avoid upgrading the substation.

[42] Again note that this battery solution is not able to claim the SGIP benefit. However the projects are expected to become operational in 2020 which the SGIP (in its current form) will have expired.

Figure 44: Electricity Storage Potential Markets



Source: EPRI

EPRI calculated the breakeven cost for this scenario at $866/kWh ($3464/kW). EPRI also calculated the effect that the energy rating (time) had on the breakeven rates. Reducing the amount of energy that could be stored from 4 hours as shown in Figure 44 to 2 hours increases the breakeven cost to $1,509/kWh. With EPRI forecasted costs of $500/kWh in 2020 electricity storage is very cost competitive. As can be seen in Figure 44, the example needs each revenue stream to be “stacked” in order to make this a viable storage asset. Remove any one of the revenue streams and then the example is no longer cost-effective.

While energy storage currently will not be cost-effective in all applications, there are many applications where energy storage will be cost-effective. As costs continue to fall for the technology, more and more storage use cases will become cost-effective. Cost-effectiveness has to be evaluated on a case-by-case basis for a particular set of operating and market parameters, which is outside the scope of this task. Currently this cost-effectiveness is assisted by the SGIP (if customer owned) and tax incentives that are available through 2015 and 2016 respectively.

CHAPTER 9: Conclusion

The goal of this task is to conceptually identify suitable generation and electricity storage technologies and the requisite sizes that would provide energy to community members in the event of an electrical outage.

In an effort to inform a range of building scales and technologies, this study considered 72 scenarios which consisted of combinations of the following:

- 3 scale scenarios
    - convention center scale
    - single building scale
    - community scale
- 2 resilience scenarios
    - 5-hour outage
    - 72-hour outage
- 12 generation and storage scenarios

Fixed-output generation — diesel generators and fuel cells — is an important requirement for maintaining the resilience criteria identified in this report. Urban buildings and the surrounding areas have limited space for the deployment of renewable generation and storage assets, and fixed-output generation offers space-efficient options.

The convention center in this study has a much higher base load than traditional residential and office buildings, which allows for the sizing of a larger fuel cell. A larger fuel cell allows more feasible outage mitigation scenarios. The single building and community scenarios have a more typical power duration curve with a high peak load due to the square footage of the buildings and a low base load due to the buildings' usage. This results in a relatively low base load and a limited fuel cell size.

For scenarios with a diesel generator during a 5-hour power outage, there is no need for storage to meet the electrical load. During a 72-hour power outage, the diesel consumption is limited to last for only 24 hours at full capacity, therefore necessitating larger storage capacities.

Li-ion batteries are more often feasible in terms of size, compared to LAES and flow batteries. Li-ion batteries have a higher storage capacity limit, since they take up less space than the other studied storage alternatives for a given storage capacity. They also have higher round trip efficiency (90%) than both LAES (70%) and flow batteries (85%). Li-ion batteries are the most expensive of the studied storage technologies, while LAES is the least expensive. These differences in cost have the largest impact on scenarios that require large storage capacities. While LAES is the cheapest storage technology, it may not be suitable in urban environments due to the industrial aesthetic impact of the plant.

HOMER has often calculated that energy storage is not required for scenarios with fixed generation. However, HOMER is a model that assesses energy on an hour-by-hour basis and does not take into account the short-term fluctuations of energy generation and supply. Energy storage is likely required for more scenarios than HOMER can model, to ensure the stability of the microgrid.

Comparing the results at the different scale scenarios shows that in most cases the cost of energy is lower at the community scale than at the single building scale. It is also notable that for the infeasible scenarios, a greater load reduction is needed for scenarios at the single building scale compared to the community scale. In addition, the community scale, when compared to the single building scale, has a feasible storage solution for each assessed generation technology. The single building could not result in a solution for the PV only or fuel cell + PV scenario, while the community scale had a solution. Scale can therefore be advantageous. Pooling both electricity demand and generation at the community level provides greater resilience opportunities. Economies of scale will also be evident for these installations.

PV is an economic choice for California, particularly when installed at the community scale, as modeled in this report. Fuel cell economics currently rely heavily on state and federal subsidies. However, fuel cells have not yet enjoyed the cost reductions that economies of scale have brought the PV industry. Energy storage provides an essential service in island mode, and the economics should be assessed on a case-by-case basis.

In addition to stationary electricity storage, electric vehicles could be used instead of stationary storage to provide microgrid support. This technology would be particularly suitable where there is fixed generation such as fuel cells and only a small amount of storage is required. A typical electric vehicle such as the Fiat 500e has a usable battery capacity of approximately 16kWh. Therefore, several vehicles would be required to plug into a microgrid in order to make a meaningful contribution to the balancing of supply and demand.

GLOSSARY

Term	Definition
Ancillary services	The services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system.
behind-the-meter generation	Generation installed on an individual customer's electricity distribution system, behind the utility meter.
CCSF	City and County of San Francisco
CIRE	Community Integrated Renewable Energy
CPUC	California Public Utilities Commission
eco-district	An urban planning tool that integrates objectives of sustainable development and reduces the ecological footprint of an area.
island	Operate independently from the utility grid
kW	kilowatt
microgrid	Microgrids are small-scale versions of the centralized electricity system. They include local generation and/or energy storage. They achieve specific local goals such as reliability, carbon emission reduction, energy arbitrage, and diversification of energy sources. They have the ability to island from the wider grid and operate independently.
MW	megawatt
NEM	net energy metering
PG&E	Pacific Gas and Electric
SoMa	South of Market
smart grid	A smart grid is a modernized electrical grid that uses information and communications technology to gather and act upon information, such as information about the behaviors of suppliers and consumers, in an automated fashion to improve the efficiency, reliability, economics, and sustainability of the production and distribution of electricity (USA, 2013).

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APPENDIX A: IES Modeling Assumptions

Table 23. Geometry of the 6 Buildings within in the Community. Note: All Buildings Include 1 floor of Retail, Included in the Dimensions in the Table.

Building	Height (ft.)	Floors (ft.)	Length (ft.)	Width (ft.)	Floorplate (ft^2)	Total
Commercial 1	168	12	280	240	46,000	550,000
Commercial 2	84	6	180	130	23,400	140,000
Commercial 3	84	6	210	170	36,000	220,000
Commercial 4	84	6	280	240	45,000	270,000
Residential 1	98	7	350	130	25,000	170,000
Residential 2	70	5	180	110	17,000	180,000
TOTAL						**1,530,000**

Commercial 1 represents the single building scale in this study.

Building data and load profiles from ASHRAE 90.1 and weather files from San Francisco Airport were used in the simulations.

Table 24: Envelope

Part	U-value (Btu/[h·ft^2·°F])	R-value: 15.3 (h·ft^2·°F)/Btu
External Wall	0.0616	15.3
Ground Floor	0.0440	18.5
Roof	0.0440	21.9
Windows	0.3482	2.87

Table 25: Internal Loads

Space use	Occupancy (ft^2/person)	People (Btu/h/person)	Miscellaneous (W/ft^2)	Interior Lighting (W/ft^2)
Commercial	275	250	0.75	0.70
Residential	250	250	0.25	0.49
Retail	300	250	0.25	1.05

Table 26: HVAC System Efficiency

System	Energy Source	Efficiency
Cooling	Electricity	COP 6.1
Heating	Natural gas	82%
DHW Delivery		80%

Table 27: Maximum Domestic Hot Water Consumption

Space use	Peak (gal/[h·person])	Average (gal/[day·person])
Commercial	0.4	1
Residential	1.7*	12*
Retail	0.8	2

*Based on the assumption that there are 3 people/apartment.

Table 28: Fenestration

Space use	Fenestration
Commercial	80%
Residential	60%
Retail	60%

APPENDIX B: HOMER Modeling Assumptions

Table 29: HOMER Inputs

HOMER Section	Data	Value	Unit	Comment
System	Simulation time step	60	minutes	HOMER default
	Dispatch Strategy	Cycle Charging		
	Set point state of charge	50	%	
Diesel Generator	Minimum load ratio	30	%	HOMER default
	Intercept coeff.	0.08	m3/hr/kW rated	HOMER default
	Slope	0.25	m3/hr/kW output	HOMER default
PV	Lifetime	25	yrs	[43]
	Derating factor	80	%	HOMER default
	Slope	37.8	degrees	HOMER default
	Azimuth	0	degrees W of S	HOMER default
	Ground reflectance	20	%	HOMER default
	Tracking	No		
Fuel cells	Lifetime	83,220	h	10 yrs, 95% of the time[44]
	Minimum load ratio	20	%	[45]
	Intercept coeff.	0.06951	m3/hr/kW rated	[46]
	Slope	0.1609	m3/hr/kW output	[47]
Solar Resource	Latitude	37° 47' N		San Francisco
	Longitude	122° 25' W		San Francisco
	Time Zone			(GMT -08:00) Pacific

[43] Typical panel manufacturers data sheet (Sunpower X21)

[44] Bloom Energy

[45] UTC Power, 2012 (now clear edge power)

[46] UTC Power, 2012 (now clear edge power)

[47] UTC Power, 2012 (now clear edge power)

				Time
Grid	Prohibit battery from discharging below power price	0.2	$/kWh	
Economics	Annual real interest rate	6	%	HOMER Default
	Project lifetime	25	yrs	HOMER Default
Converter	Costs	0	$/kW	Included in PV and fuel cell costs
	Inverter efficiency	100	%	
Constraints	Maximum annual capacity shortage	0	%	
	Minimum renewable integration	0	%	
Operating reserve				HOMER default settings

Storage

Table 30: Storage Properties

	Li-ion	LAES	Flow Battery	Unit
Nominal Capacity	281.53	281.53	281.53	Ah
Nominal Voltage	710.4	710.4	710.4	V
Roundtrip Efficiency	90	70	85	%
Min. State of Charge	20	0	0	%
Float Life	10	20	8	Yrs
Lifetime Throughput	14,000,000	-	-	kWh
Maximum Charge Rate	1	1	1	A/Ah
Maximum Charge Current	5.5	5.5	5.5	A

Table 31: Capacity Curve for All Storage Technologies

Discharge Current (A)	Capacity (Ah)
1	295
5	255
7	242
14	212
21	187
28	168
42	133
70	85

APPENDIX C: Results from HOMER simulations

Table 32: HOMER Simulations Results

Scale	Resilience	Generation (kW)			Storage (kWh)			Cost of Energy ($/kWh)	Feasible?	Feasible Load
		Diesel Generator	Fuel Cell	PV	Li-ion	LAES	Flow Battery			
Convention Center	**5 hr**			900	6000			0.410	X	70%
				900		7600		0.230	X	10%
				900			6400	0.260	X	25%
		1000		900	0			0.193	✓	
		1000		900		0		0.193	✓	
		1000		900			0	0.193	✓	
			600	900	0			0.212	✓	
			600	900		0		0.212	✓	
			600	900			0	0.212	✓	
		1000	600	900	0			0.234	✓	
		1000	600	900		0		0.234	✓	
		1000	600	900			0	0.234	✓	
	72 hr			900	36000			2.102	X	10%
				900		36000		0.583	X	5%
				900			32000	0.801	X	5%
		1000		900	3600			0.410	X	55%
		1000		900		7200		0.301	X	30%
		1000		900			4400	0.305	X	45%
			600	900	0			0.232	✓	
			600	900		0		0.232	✓	
			600	900			0	0.232	✓	
		1000	600	900	0			0.260	✓	
		1000	600	900		0		0.260	✓	
		1000	600	900			0	0.260	✓	
Single Building	**5 hr**			700	6800			0.611	X	45%
				700		8400		0.286	X	15%
				700			7200	0.341	X	25%
		1000		700	0			0.217	✓	
		1000		700		0		0.217	✓	
		1000		700			0	0.217	✓	
			60	700	6400			0.592	X	50%
			60	700		8000		0.289	X	20%
			60	700			6800	0.340	X	30%

		1000	60	700	0			0.219	✓	
		1000	60	700		0		0.219	✓	
		1000	60	700			0	0.219	✓	
	72 hr			700	28000			2.605	X	20%
				700		24000		0.626	X	10%
				700			24000	0.944	X	15%
		1000		700	800			0.320	✓	
		1000		700		800		0.271	✓	
		1000		700			800	0.280	✓	
			60	700	24000			2.254	X	25%
			60	700		24000		0.637	X	15%
			60	700			24000	0.956	X	20%
		1000	60	700	400			0.295	✓	
		1000	60	700		400		0.270	✓	
		1000	60	700			400	0.275	✓	
Community	**5 hr**			3000	11600			0.500	✓	
				3000		13600		0.272	X	35%
				3000			12000	0.311	X	55%
		2750		3000	0			0.245	✓	
		2750		3000		0		0.245	✓	
		2750		3000			0	0.245	✓	
			250	3000	9200			0.449	✓	
			250	3000		12000		0.276	X	45%
			250	3000			10400	0.309	X	65%
		2750	250	3000	0			0.253	✓	
		2750	250	3000		0		0.253	✓	
		2750	250	3000			0	0.253	✓	
	72 hr			3000	36000			1.357	X	35%
				3000		36000		0.456	X	20%
				3000			32000	0.584	X	25%
		2750		3000	800			0.304	✓	
		2750		3000		1600		0.286	✓	
		2750		3000			1200	0.290	✓	
			250	3000	24000			0.978	X	50%
			250	3000		32000		0.442	X	30%
			250	3000			28000	0.550	X	35%

	2750	250	3000	0			0.284	✓
	2750	250	3000		0		0.284	✓
	2750	250	3000			0	0.284	✓

APPENDIX F:
Task 6: CIRE Potential Quantification

Energy Research and Development Division
FINAL PROJECT REPORT

COMMUNITY INTEGRATED RENEWABLE ENERGY PROJECT

Task 6: CIRE Potential Quantification

Prepared for: California Energy Commission
Prepared by: Arup, for the San Francisco Department of the Environment

ARUP

OCTOBER 2014
CEC-500-2014-OCT

CHAPTER 1: Introduction

Project Description

The Community Integrated Renewable Energy (CIRE) Project will assess the feasibility of community energy, district heating and cooling, renewable electricity, storage and energy recovery, demand response, and microgrid distribution technology to serve community members and their energy needs.

The CIRE Project consists of the following tasks and subject areas:

- Task 1: Administrative and Reporting
- Task 2: Distributed Generation Connected to the Electricity Network
- Task 3: Community Generation and Enabling Technologies
- Task 4: Energy Storage and Generation Analysis
- Task 5: District Thermal Energy Concept
- Task 6: CIRE Potential Quantification
- Task 7: Dissemination

This report provides our findings for Task 6: CIRE Potential Quantification.

The goal of this task is to demonstrate the ROM of the potential environmental and economic benefits that could be achieved through state-wide adoption of CIRE technologies.

The goal was achieved through analysis of the following recommendations:

Cover Those Cars

Using existing and new parking lots for CIRE generation is an efficient use of the space. PV integrated with parking provides useful shading to parking spaces and can be designed to ensure it does not affect the long-term operation of the parking facility.

This report presents an ROM estimation of the potential generation from parking lot PV implemented in San Francisco, as well as in four other cities and the state of California altogether, by scaling the San Francisco results based on parking spaces per registered car. It also analyzes the environmental and economic benefits of such systems.

Connect Those Buildings

Building on the Task 5 study, this task presents an ROM estimate of the economic and environmental benefits that could be achieved by connecting existing buildings in the core downtown areas of cities to a district thermal system.

This report presents the ROM capital cost associated with creating a district thermal system and connecting buildings to it, as well as the ROM operational cost reductions achieved through operations and maintenance (O&M) optimization and energy efficiency. The resulting ROM environmental benefits are also calculated and presented at the city and state level.

Power Those Roads

This task explores the economic and environmental benefits associated with converting our roads and highways from single-use infrastructure (i.e., driving) to dual-purposed infrastructure (i.e., driving and energy generation).

This report presents the ROM capital cost associated with deploying PV along state roads and highways, as well as the subsequent ROM energy generation and carbon reduction.

CHAPTER 2: Cover Those Cars

Methodology

Open Parking Lot Area

San Francisco

The parking lot area available for PV in San Francisco was estimated using off-street parking data from SF Park (SFMTA),[1] from both garages and parking lots. This data contains the following:

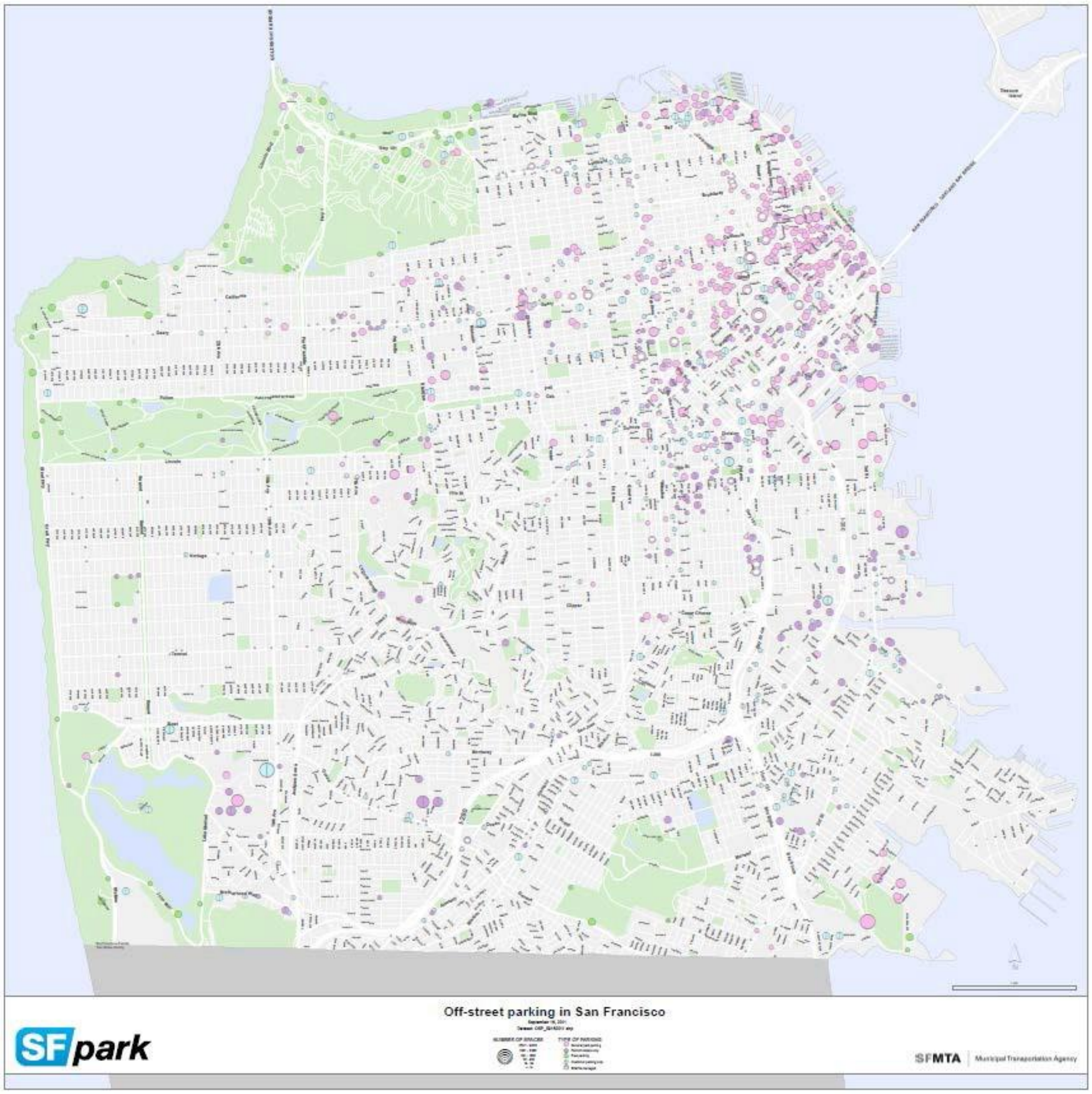
- Paid, publicly available: drive up and pay, typically by the hour or by the day
- Customer parking only: typically for businesses or religious institutions
- Permit holder only: e.g., employees only, students only, monthly only
- Free publicly available: free off-street parking

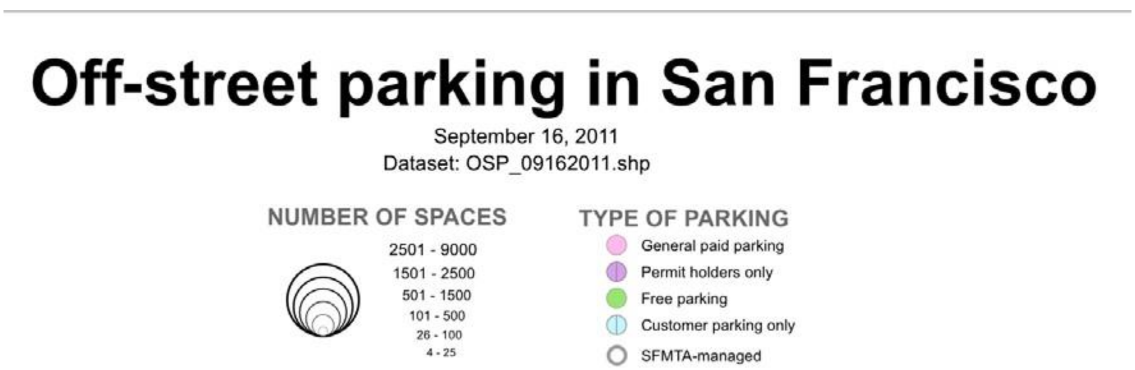
The data does not include the following:

- Off-street residential parking spaces
- Other unmarked private parking

[1] SF Park (SFMTA). "Off-street parking census GIS data." Accessed September 30, 2014; last modified September 20, 2011. http://sfpark.org/resources/off-street-parking-census-gis-data/

Figure 1: Off-street parking in San Francisco[2]





[2] SF Park, 2011.

The average area of a parking space in San Francisco was estimated to be 144ft² (8ft x 18ft). A typical garage in San Francisco was assumed to be three stories; therefore, one-third of the total spaces in garages are on the top level and can be covered by a PV canopy. The estimated parking area is summarized in Table 1 and suggests there is about 16 million ft² of parking space area available for PV in San Francisco.

Table 1: Estimated Parking Area Available for PV

Type	# Structures	# Spaces	Parking Area (ft²)	PV Area (ft²)
Garage	400	83,000	12,000,000	4,000,000
Lot	1,000	86,000	12,400,000	12,400,000
Total	1,400	170,000	24,400,000	16,400,000

California

The parking area available for PV in the rest of California was estimated by applying the estimated parking spaces per registered car[3] for San Francisco (0.21 garage spaces and 0.22 lot spaces) to four other major metropolitan areas — San Jose, Los Angeles, San Diego, and Sacramento — as well as on a state-wide scale. The estimated areas available for PV is presented in Table 2.

Table 2: Estimated available parking space PV area

Location	PV area (ft²)
San Francisco County	16,400,000
Santa Clara County (San Jose)	52,800,000
Los Angeles County	251,000,000
San Diego County	84,300,000
Sacramento County	34,900,000
California total	959,500,000

Shading

Parking lots are often shaded by surrounding buildings. This affects the amount of electricity that can be generated from the PV systems. Detailed shading calculations were not performed in this study; however, an estimation of shading effects was made based on the presence of tall buildings to the south of some of the identified parking lots. The total shading factor was based

[3] Department of Motor Vehicles. *Estimated vehicles registered by county for the period of January 1 through December 31, 2013,* 2014.

on estimations performed in the CIRE Task 3 report[4] for the downtown area of San Francisco (presented in Table 3). This gives an average shading factor of 88%, which is applied on all parking spaces in this study.

Table 3: Estimation of Average Shading Factor

Shading	Shading factor	% of downtown SF parking area	Average shading factor
Minimal	1	43%	0.88
Slight	0.875	54%	
Significant	0.65	3%	

PVWatts tool

The generation factor of 1 kW installed capacity for each climate zone was estimated using the PVWatts model (8th September 2014 version), an online PV simulation tool developed by the National Renewable Energy Laboratory (NREL). A new version of the tool was recently released, in which the results better reflect PV performance output from current systems and the new PVWatts model was used for the calculations in this report.

Simulations were performed for each of the studied cities. The generation factor for California was assumed to be an average of all 16 climate zones.[5] The assumptions used in the simulations are presented in Table 4.

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[4] Carr, Russ; O'Brian, Jordan; Roberts, Cole. *CIRE Task 3A: Community Energy and Enabling Technologies Use Case – Electricity*. San Francisco, 2014

[5] California Energy Commission. "California Energy Maps." accessed September 24, 2014, http://www.energy.ca.gov/maps/renewable/building_climate_zones.html

Table 4: PVWatts Assumptions

Module Type	Standard
Array Type	Fixed (open rack)
System Losses (%)	14
Shading Factor (%)	88
Tilt (deg)	20
Azimuth (deg)	180

Calculations

The research team assumed that the PV installed on a parking structure will have an average capacity of 9.3W[6]/ft^2 to allow for the safe operation of the parking lot and provide free space in-between parking stalls to allow vehicle movement. A typical high-efficiency roof-mount PV array will have a density of around 15-18W/ft^2.

To calculate the PV potential, 9.3W/ft^2 was multiplied by the identified parking lot's area. The generation factor, calculated with the PVWatts tool, was then used to determine the annual electricity production of the PV systems.

Results

The results are presented in Table 5. The lifetime is assumed to be 20 years.

Table 5: Parking PV generation

Location	Generation factor	Generation		
	kWh/kW/yr	kWh/ft^2/yr	GWh/yr	GWh/lifetime
San Francisco County	1,530	14.23	210	3,700
Santa Clara County (San Jose)	1,569	14.59	680	12,300
Los Angeles County	1,587	14.76	3,260	59,000
San Diego County	1,629	15.15	1,120	20,300
Sacramento County	1,533	14.26	440	7,900
California total	1,564	14.54	12,280	222,300

[6] This value was calculated from an existing installation, the Schletter PV Plant in Germany. It has a 500kW parking lot PV array, which takes 53,770ft^2 of parking space including access lanes.

Environmental Benefits

Reduction of emissions was calculated using emissions data based on metrics from the Emissions & Generation Resource Integrated Database (eGRID)[7], presented in Table 6. Since the most recent files available are from 2010, numbers were calculated with the assumption that power mix and emissions numbers in 2014 are comparable to those in 2010.

Table 6: CO_2 Emission Factors

Gas	Emissions Factor (metric tons [MT]/GWh)
CO_2	232
NO_X	0.0781
SO_2	0.0610
CH_4	0.0139
N_2O	0.00201

The estimated emissions reductions of CO_2, NO_X, SO_2, CH_4, and N_2O are shown in Table 7. The total reduction in greenhouse gas (GHG) emissions are presented in CO_2 equivalent (CO_2e) in Table 8. The CO_2e reduction is calculated over a lifetime of 20 years, where the emission factors are assumed to stay unchanged throughout the lifetime.

Table 7: Estimated CO_2 Emissions Reduction

Location	CO_2 MT/yr	NO_X MT/yr	SO_2 MT/yr	CH_4 MT/yr	N_2O MT/yr
San Francisco County	48,000	16	13	3	0.4
Santa Clara County (San Jose)	157,000	53	41	9	1
Los Angeles County	756,000	254	199	45	7
San Diego County	261,000	88	68	16	2
Sacramento County	102,000	34	27	6	1
California total	2,848,000	959	749	171	25

[7] US Environmental Protection Agency (EPA). "eGRID" (The Emissions & Generation Resource Integrated Database), last updated August 5, 2014. http://www.epa.gov/cleanenergy/energy-resources/egrid/

Table 8: Estimated CO_2e Emissions Reduction

Location	CO_2e MT/yr	CO_2e MT/lifetime
San Francisco County	48,000	866,000
Santa Clara County (San Jose)	158,000	2,858,000
Los Angeles County	759,000	13,739,000
San Diego County	262,000	4,734,000
Sacramento County	102,000	1,844,000
California total	2,859,000	51,753,000

Economic Benefits

Jobs and Economic Impacts

The Jobs and Economic Development Impact (JEDI) model[8] was used to calculate job creation and regional economic impacts associated with PV installation over available parking areas in California. This tool, developed by NREL, calculates both local and total employment and economic impact. Local spending is defined as follows:

- Local labor (e.g., concrete pouring jobs)
- Services (e.g., engineering, design, legal)
- Materials (e.g., wind turbine blades)
- Other components (e.g., nuts and bolts)

Total capacity was inputted as a single system in order to provide a conservative estimate of jobs created and economic input/output values (a higher number of projects would yield higher numbers).

Table 9 summarizes the input data used in the model.

Table 9: JEDI Model Assumptions and Inputs

Parameter	Input
Project location	California
Year of installation	2014
System application	Small commercial
System tracking	Fixed mount
Base installed system cost[9]	$3,920/kW DC
Annual direct O&M cost[10]	$19/kW/yr
Project cost data	JEDI defaults

[8] NREL. "JEDI Jobs and Economic Development Impact Models". Last updated June 19. 2013, http://www.nrel.gov/analysis/jedi/

[9] Mahone, A. K. *Cost-Effectiveness of Rooftop Photovoltaic Systems for Consideration in California's Building Energy Efficiency Standards*. California Energy Commission, 2013. States that PV costs around $4.6/W installed. Added to this is $1/W for the parking capony structure. We have then assumed that the 30% tax credit would apply to these projects, giving a total installed cost of $3.92/W

[10] NREL. "Distributed Generation Renewable Energy Estimate of Costs." Estimate of costs for 10-100 kW. Last updated January 22, 2014, http://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html

Table 10 presents the estimated number of full time jobs created, where a full time employee (FTE) is assumed to work 2080 hours per year.

Table 10: Estimated Number Full-Time Jobs Created

Location	Jobs During Construction/ Installation Period # FTE/yr	Jobs During Operating Years # FTE/yr	Jobs over Lifetime # FTE/yr
San Francisco County	5,000	60	6,000
Santa Clara County (San Jose)	17,000	200	21,000
Los Angeles County	80,000	930	100,000
San Diego County	27,000	310	33,000
Sacramento County	11,000	130	14,000
California total	308,000	3,600	380,000

Table 11and Table 12 present the estimated local and total costs.

Table 11: ROM Local Costs

Location	Construction & Installation Costs $M/lifetime	Annual Operational Expenses $M/yr	Lifetime (20 yr) Costs $M/lifetime
San Francisco County	400	4	500
Santa Clara County (San Jose)	1,200	13	1,500
Los Angeles County	5,600	62	6,900
San Diego County	1,900	21	2,300
Sacramento County	800	9	1,000
California total	21,600	238	26,400

Table 12: ROM Total Costs

Location	Construction & Installation Costs $M/lifetime	Annual Operational Expenses $M/yr	Lifetime (20 yr) Costs $M/lifetime
San Francisco County	600	70	2,100
Santa Clara County (San Jose)	1,800	220	6,800
Los Angeles County	8,600	1,030	32,500
San Diego County	2,900	350	10,900
Sacramento County	1,200	140	4,500
California total	32,700	3,900	124,300

Financial Benefits (Customer Savings)

To calculate customer savings, the research team used the average retail price in July 2014 of electricity to ultimate customers by end-use sector for California and produced a 20 year levilized cost of ($0.24/kWh)[11] and a levelized cost of energy for installed PV ($0.187/kWh).[12] System lifetime was assumed to be 20 years with a utility price escalator of 3% per year and 0% for PV production. The ROM estimated customer savings are presented in Table 13.

Table 13: ROM Estimated Customer Savings

Location	Electricity Lifetime Savings with 3% Utility Price Escalation ($M/lifetime)
San Francisco County	200
Santa Clara County (San Jose)	600
Los Angeles County	2,700
San Diego County	1,000
Sacramento County	400
California total	10,400

[11] US Energy Information Administration (EIA). "Electric Power Monthly – Data for July 2014." last updated September 25, 2014. http://1.usa.gov/1y8HWq6

[12] 20 year period, 3.0% discount rate, $3.92/W capital cost, O&M of $19/kW/yr.

CHAPTER 3:
Connect Those Buildings

Methodology

The heat recovery and energy savings potential for the downtown areas of San Francisco, San Jose, Los Angeles, San Diego, and Sacramento were estimated using the District Energy Feasibility (DEF) tool developed by Arup.

DEF Tool Inputs

Estimation of the buildings' floor area supplied by the district thermal systems was based on Class A (office) building inventory statistics (Table 14). Residential, hotel, and retail areas were estimated using the split between building types in San Francisco (Table 15).

Table 14: Class A (Office) Buildings Inventory

Location	Floor area (ft^2)
San Francisco[13]	48,400,000
San Jose[14]	3,900,000
Los Angeles[15]	38,000,000
San Diego[16]	5,500,000
Sacramento[17]	9,100,000

[13] BOMA (Building Owners and Managers Association) San Francisco, via Bozeman, John (Manager, Government and Public Affairs)

[14] Newmark Cornish & Carey, Silicon Valley Class A Office Market, Q3 '14

[15] BOMA Greater Los Angeles via Brown, Desmond (Director of Business Development and Member Relations). Co Star data from the 2nd quarter of 2014

[16] Cushman & Wakefield, Office Market Statistics by Class, data for Q3 2014

[17] Cassidy Turley, Office Report, Sacramento Valley, data for Q2 2014

Table 15: Split of Land Use Type [18,19]

Land Use Type	Split
Office	57%
Retail	7%
Hotel	11%
Residential	25%

Table 16: Total Estimated Building Inventory

Land Use Type	San Francisco (ft^2)	Los Angeles (ft^2)	Sacramento (ft^2)	San Diego (ft^2)	San Jose (ft^2)
Office	48,400,000	38,000,000	9,100,000	5,500,000	3,900,000
Retail	5,900,000	4,600,000	1,100,000	700,000	500,000
Hotel	8,900,000	7,000,000	1,700,000	1,000,000	700,000
Residential	21,400,000	16,800,000	4,000,000	2,400,000	1,700,000
Total	84,600,000	66,500,000	15,900,000	9,700,000	6,700,000

The Energy Use Intensity (EUI) values for the different space uses and locations, presented in Table 17, were mainly obtained from the DOE Building Performance Database. Where data was missing, estimations based on differences in cooling and heating degree days were used.[20]

Table 17: EUI for Different Space Uses and Locations

Space Use	San Francisco	San Jose	Los Angeles	San Diego	Sacramento
Commercial	55	56	54	47	71
Residential	95	53	78	22	66
Hotel	66	91	85	103	77
Retail	32	28	32	21	21

[18] Edmondson, Scott. San Francisco Planning Department

[19] San Francisco Planning Department. *Downtown Plan Annual Monitoring Report 2013*. July 2014

[20] DOE Building Performance Database. Accessed October 10. 2014, https://bpd.lbl.gov/

The capital investment required for district energy systems is highly dependent on the length of the distribution network. The longest distribution run within a network was used as a proxy to estimate the overall distribution capital investment. For San Francisco, this length was per the core downtown area described in the *Downtown Plan Annual Monitoring Report 2013*, while for other cities a visual estimation was made based on the density of tall and dense downtown buildings.

The longest distribution run is also an important parameter for estimating distribution pressure requirements, and it was therefore also used in the DEF model to estimate district pumping energy.

Table 18: Longest Pipe Run (Supply and Return)

Location	Longest run (ft)
San Francisco	27,200
San Jose	15,600
Los Angeles	20,600
San Diego	23,600
Sacramento	20,000

Result

In this study a central heating and cooling system with heat recovery chillers was chosen as the district thermal energy technology. (This scheme is further described in the CIRE Task 5: Community Integrated Renewable Energy Project[21].)

By reusing unwanted heat from spaces demanding air conditioning into spaces concurrently demanding heat, this technology also capitalizes on the mix of commercial, retail, and residential buildings which have complimentary use schedules. The potential for year-round low-temperature heat recovery for the studied cities are illustrated in Figure 2 through Figure 6

[21] Calvén, Alexandra; Naqvi, Afaan; Roberts, Cole. *CIRE Task 5: District Thermal Energy Concepts*. San Francisco, 2014

Figure 2: Heat Recovery Potential for San Francisco

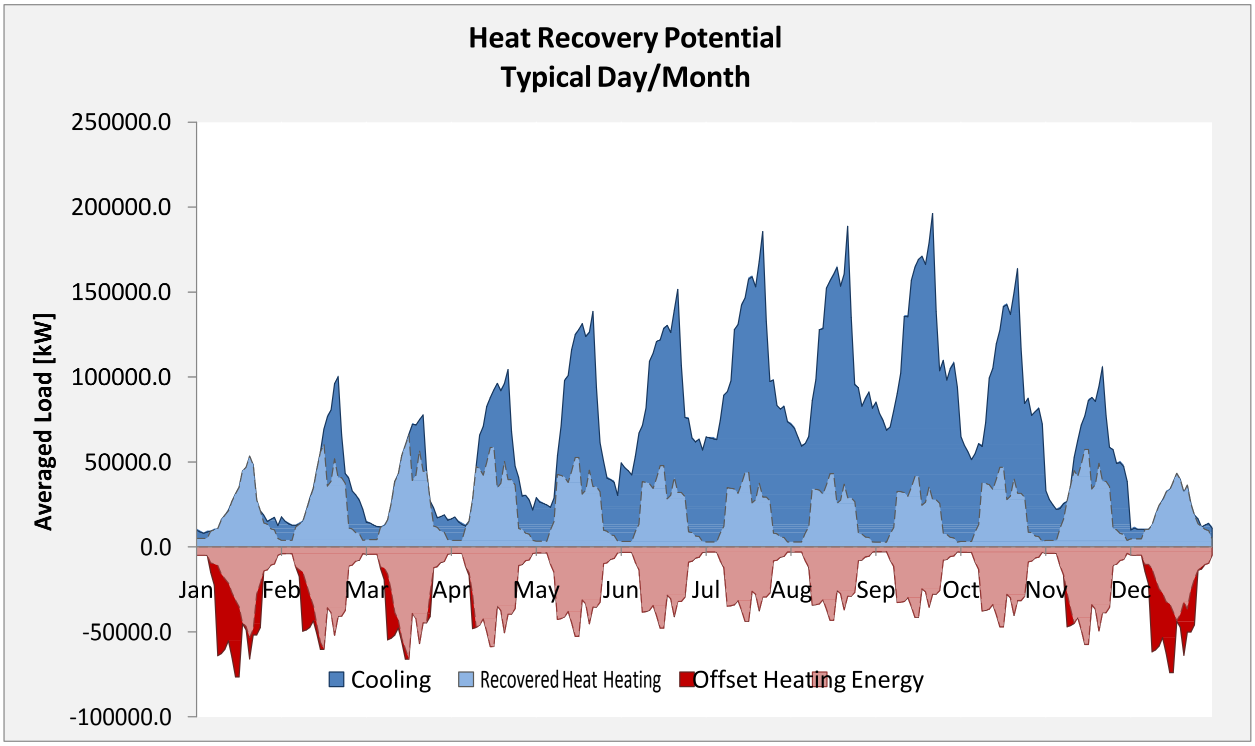


Figure 3: Heat Recovery Potential for San Jose

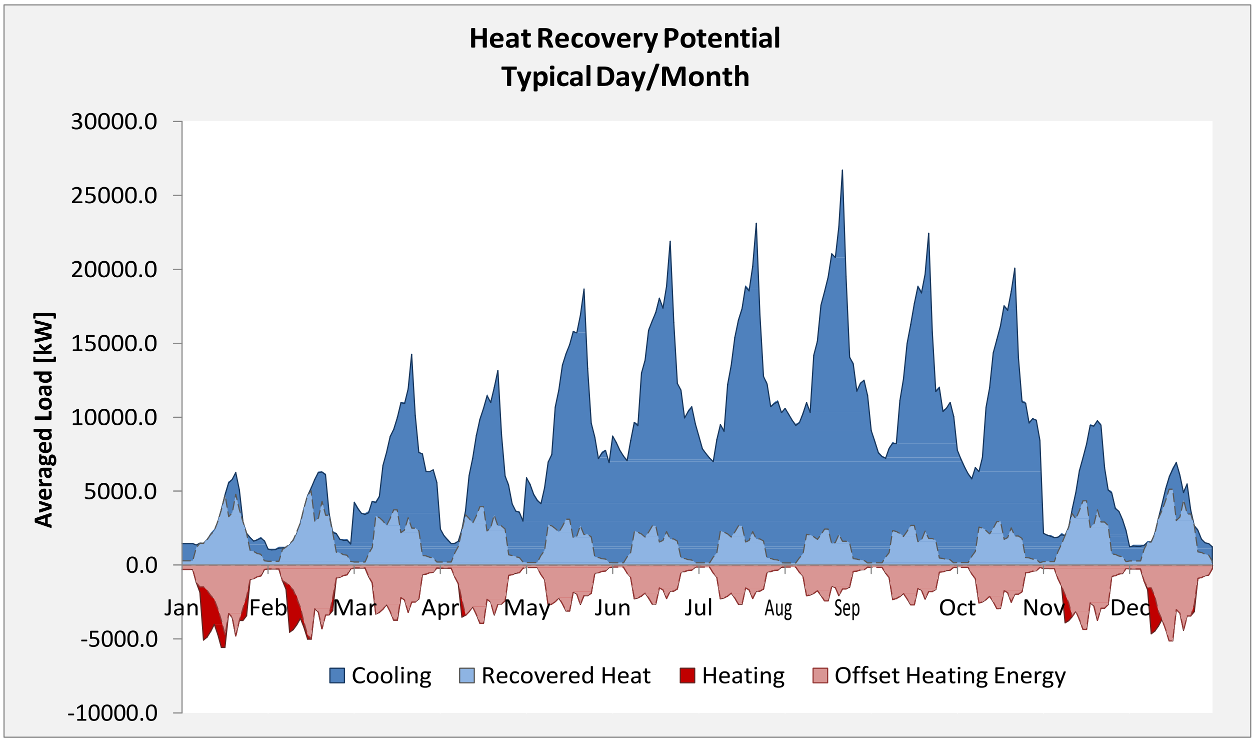


Figure 4: Heat Recovery Potential for Los Angeles

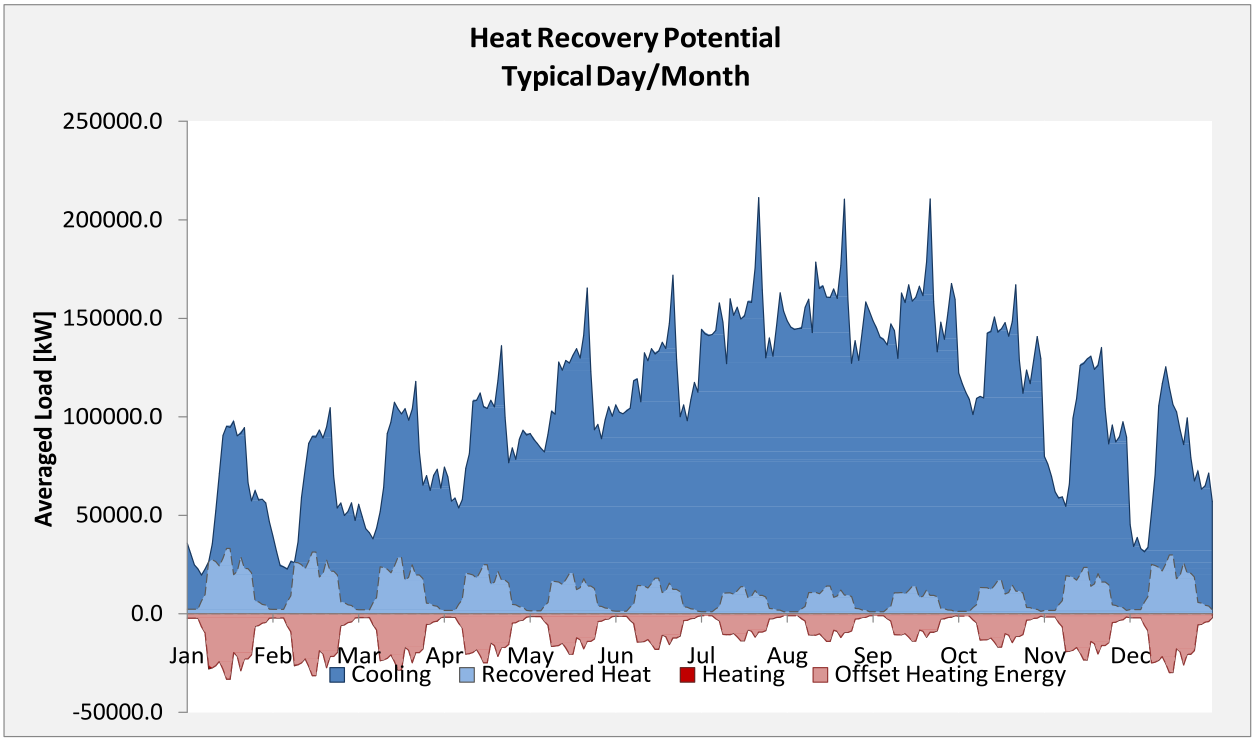


Figure 5: Heat Recovery Potential for San Diego

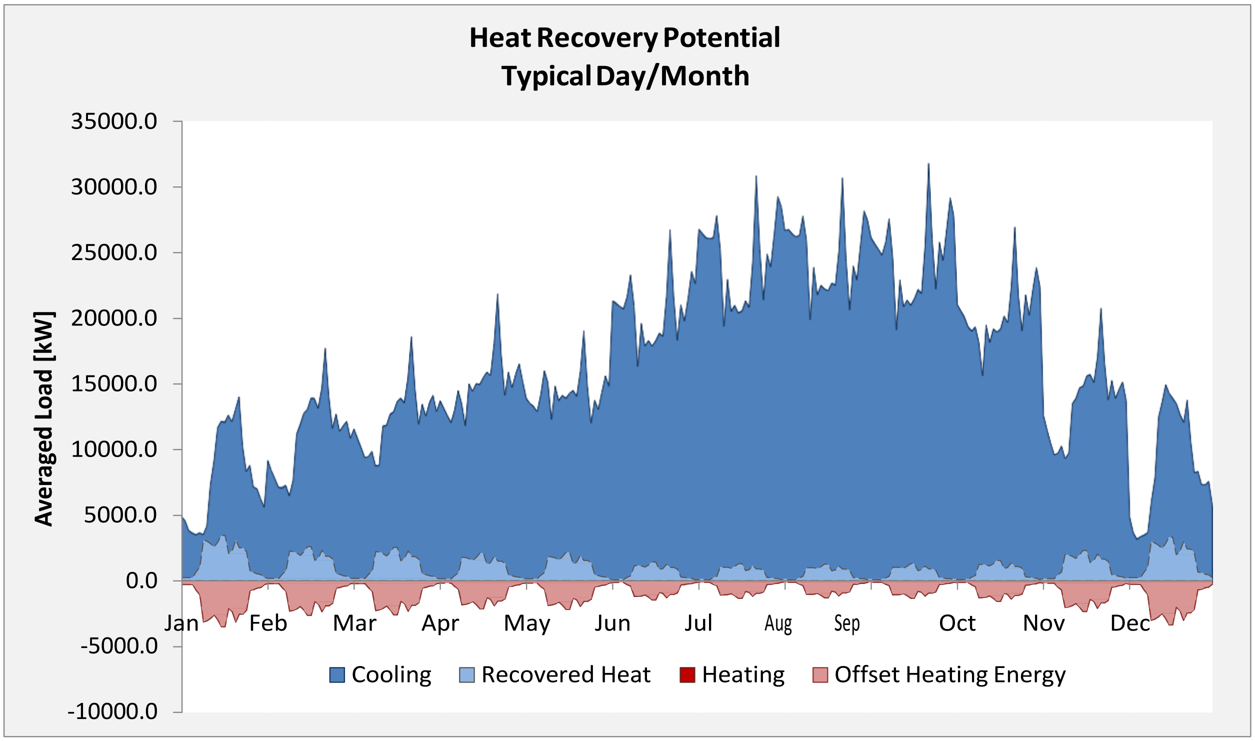
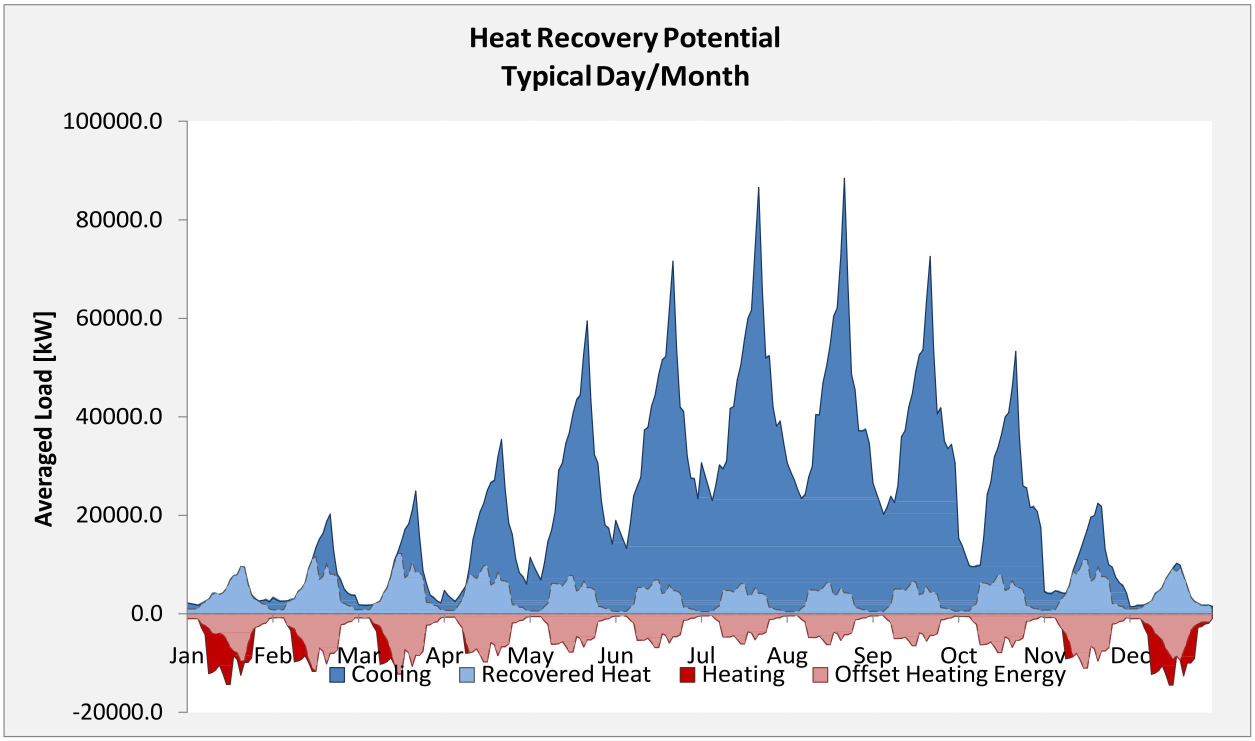


Figure 6: Heat Recovery Potential for Sacramento



The heat recovery potential is greatest in San Francisco, due to its mild climate. In hotter climates, especially in San Diego and Los Angeles, the heat recovery potential is lower compared to the peak cooling loads experienced at the city scale.

The total energy savings are presented in Table 19. There are significant savings in gas consumption. However, the electricity consumption increases, which can be explained by increased thermal losses in the distribution network, as well as increased pumping energy.

Table 19: Estimated Total Energy Savings

Location	Electricity MWh/yr	Gas Therms/yr	Total Energy MWh/yr
San Francisco	-30,000	6,280,000	153,000
San Jose	-2,000	480,000	12,000
Los Angeles	-44,000	3,210,000	50,000
San Diego	-8,000	300,000	1,000
Sacramento	-7,000	1,070,000	24,000
Cities Total	-91,000	11,330,000	240,000

The energy savings potential is greatest in San Francisco, which can be explained by the high building density of the downtown area and the heat recovery potential. The building density of the other cities studied is much lower, which in combination with reduced heat recovery potential makes district thermal less efficient. However, for example in San Diego there are clusters of high-rise buildings and it would probably make more sense to have 2-3 smaller district cooling systems than to connect the whole downtown area. The difference in building density between San Francisco (85 million ft^2 within 27,200 feet of distribution) and San Diego (10 million ft^2 within 23,600 feet of distribution) is illustrated in Figure 7 and Figure 8: Assumed District Energy Area in San Diego (blue line shows longest pipe run).

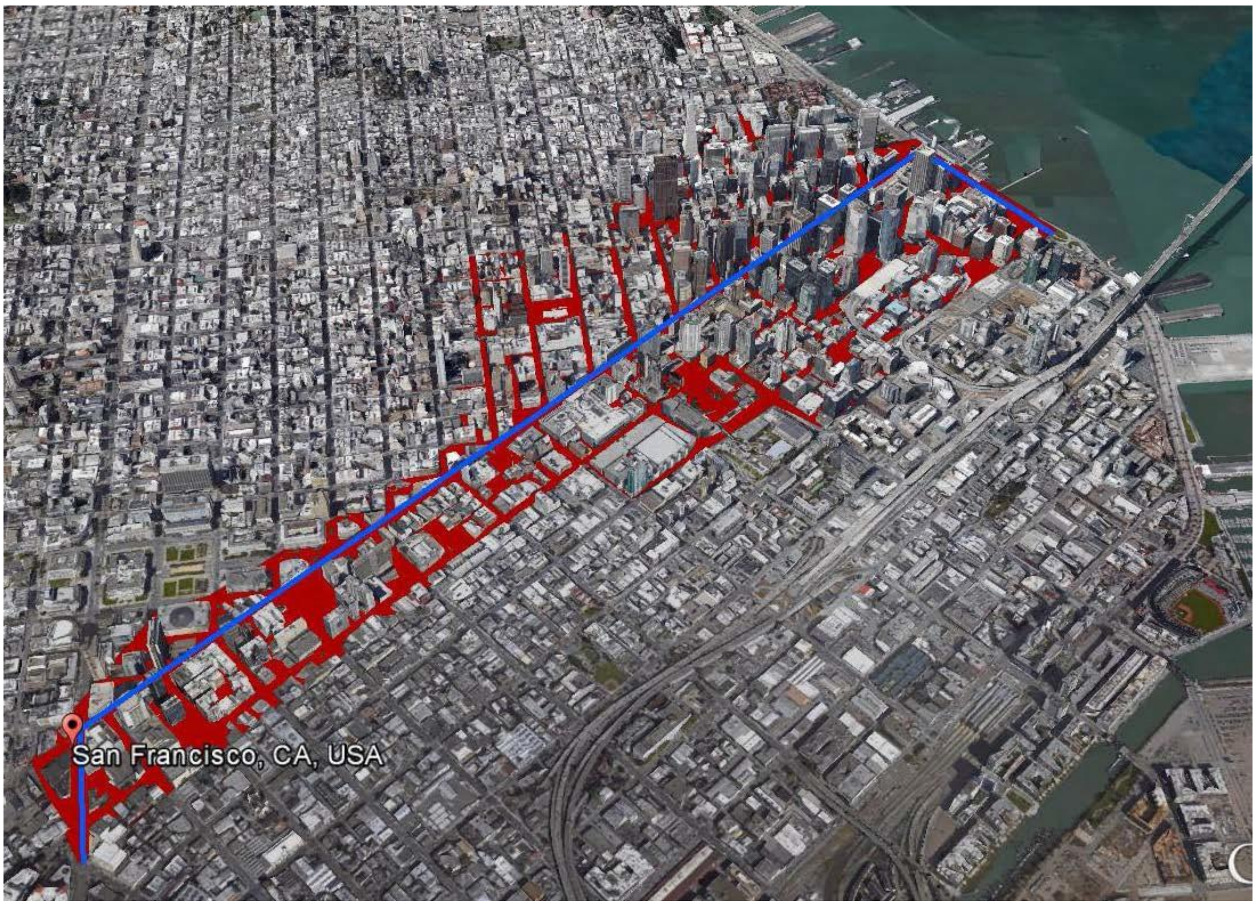


Figure 7: Assumed District Energy Area in San Francisco

Figure 8: Assumed District Energy Area in San Diego

Environmental Benefits

When calculating the environmental benefits of a district thermal system, the emissions reduction from the reduced use of natural gas must be compared with the increased emissions from the increased electricity demand.

The calculation is based on electricity emission factors used in CHAPTER 2: Cover Those Cars (Table 6) and natural gas emission factors presented in Table 20.

Table 20: CO_2 Emission Factors

Gas	Emissions Factor metric tons CO_2/therm
CO_2	0.00531[22]
CH_4	0.000000105[23]
N_2O	0.0000000105[22]

The total estimated emissions reductions of CO_2, NO_X, SO_2, CH_4, and N_2O are shown in Table 21. The total reduction in GHG emissions are presented in CO_2 equivalent in Table 22. The CO_2 equivalent reduction is calculated over a lifetime of 25 years, where the emission factors are assumed to stay unchanged throughout the lifetime.

All cities show reduction in CO_2 and CO_2e emissions, except from San Diego where the emissions from the increased electricity demand are greater than the reduction from the gas savings.

Table 21: Estimated Total CO_2 Emissions Reduction

Location	CO_2 MT/yr	NO_X MT/yr	SO_2 MT/yr	CH_4 MT/yr	N_2O MT/yr
San Francisco County	26,200	-2.4	-1.9	0.24	0.005
Santa Clara County (San Jose)	6,900	-3.4	-2.7	-0.27	-0.054
Los Angeles County	4,000	-0.6	-0.4	0.01	-0.003
San Diego County	-400	-1.2	-0.9	-0.15	-0.025
Sacramento County	2,000	-0.2	-0.1	0.02	0.0002
California total	38,700	-7.7	-6.0	-0.15	-0.076

Table 22: Estimated CO_2 equivalent emissions reduction

[22] US Energy Information Administration (EIA). "Carbon Dioxide Emissions Coefficients". Last updated February 4. 2013, http://www.eia.gov/environment/emissions/co2_vol_mass.cfm

[23] Gómez, Dario et al. *2006 IPCC Guidelines for National Greenhouse Gas Inventories*. "Chapter 2 Stationary Combustion". 2006

Location	Electricity MT/yr	Natural Gas MT/yr	Total MT/yr	Electricity MT/lifetime	Natural Gas MT/lifetime	Total MT/lifetime
San Francisco	-7,100	33,300	26,300	-177,500	832,500	657,500
San Jose	-10,200	17,000	6,900	-255,000	425,000	172,500
Los Angeles	-1,600	5,700	4,000	-40,000	142,500	100,000
San Diego	-3,600	3,100	-500	-90,000	77,500	-12,500
Sacramento	-600	2,600	2,000	-15,000	65,000	50,000
Cities Total	-23,100	61,700	38,700	-577,500	1,542,500	967,500

Economic Benefits

The capital costs for the plant were based on data from ASHRAE. The distribution and building costs as well as the operating costs were based on the methodology used in the CIRE Task 5 report.[24] The cost data is presented in Table 23.

Table 23: Cost data

Item	Cost
Cooling plant	1,800 $/tons
Heating plant	1,500 $/HP
Distribution	8,700 $/trench ft
Building	1 $/ft^2

The savings in operating costs include energy, water and operation and maintenance savings. The calculations account for the expected cost of these over time, including escalation pricing. The water savings and O&M assumptions are described in APPENDIX A.

The ROM capital costs are presented in Table 24 and the operating costs savings, over a lifetime of 25 years, are presented in Table 25. The result shows that the operating costs savings are greater than the capital costs for all of the cities, which confirms that district energy makes sense from a financial point of view.

[24] Calvén, Alexandra; Naqvi, Afaan; Roberts, Cole. *CIRE Task 5: District Thermal Energy Concepts*. San Francisco, 2014

Table 24: ROM Capital Costs

Location	Plant $M	Distribution $M	Buildings $M	Total $M
San Francisco	362	118	114	553
San Jose	30	68	9	103
Los Angeles	253	89	89	400
San Diego	30	102	13	141
Sacramento	73	87	21	173
Cities Total	749	463	246	1,370

Table 25: ROM Operating Cost Savings

Location	Energy $M	Water $M	O&M $M	Total $M
San Francisco	231	69	2,020	2,320
San Jose	18	4	160	180
Los Angeles	118	19	1,590	1,730
San Diego	11	0	230	240
Sacramento	39	9	380	430
Cities Total	417	100	4,390	4,910

CHAPTER 4: Cover Those Roads

Methodology

The estimation of the maximum amount of PV that could be safely installed on California's state roads and highways was provided by the California Department of Transportation (Caltrans), which manages the state highway system (including over 50,000 miles of California's highway and freeway lanes).

The estimation is based on a study performed in 2011, where the potential for PV development at specified Caltrans properties (consisting of 347 interchanges, 3 park and ride lots, and 9 other Caltrans-owned sites) was explored.

All potential PV generation near operating Caltrans highway facilities is restricted by a buffer, Clear Recovery Zone (CRZ), which provides an unobstructed area that allows drivers to recover from errant lane departures. Placement of discretionary fixed objects that can be struck by vehicles in the CRZ is not allowed as this negatively impacts driver safety. Potential sites for PV generation are thereby heavily reduced due to this constraint.

Results

The study concluded that the interchanges were the most suitable sites and up to 126 MW of potential PV capacity[25] can be safely installed within these locations. Table 26 presents the estimated resulting PV generation per year and over a lifetime of 20 years.

Table 26: Estimated PV Capacity[26]

Location	PV Capacity	Generation factor	Total generation	
	kW	kWh/kW/yr	GWh/yr	GWh/lifetime
California total	126,000	1,564	200	3,600

[25] Economics to date have been a large development barrier to adoption of this strategy.

[26] California Department of Transportation (Caltrans), via Fredrickson, Paul.

Environmental Benefits

The emissions reduction calculation is based on electricity emission factors used in CHAPTER 2: Cover Those Cars (Table 6).

The estimated emissions reductions of CO_2, NO_X, SO_2, CH_4, and N_2O are shown in Table 7. The total reduction in GHG emissions are presented in CO_2 equivalent (CO_2e) in Table 8. The CO_2e reduction is calculated over a lifetime of 20 years, and the emission factors are assumed to stay unchanged throughout the lifetime.

Table 27: Estimated CO2 Emissions Reduction

Location	CO_2 MT/yr	NO_X MT/yr	SO_2 MT/yr	CH_4 MT/yr	N_2O MT/yr
California total	45,700	15	12	3	0.4

Table 28: Estimated CO_2 equivalent emissions reduction

Location	CO_2e	
	MT/yr	MT/lifetime
California total	45,900	830,000

Economic Benefits

Jobs and Economic Impact

The Jobs and Economic Development Impact (JEDI) model (described in CHAPTER 2: Cover Those Cars) was used to calculate job creation and regional economic impacts associated with PV installations on California's roads and highways. A levelized cost of energy of $0.187/kWh[27] was used for the roadside PV.

Table 29 presents the estimated number of full time jobs created, where a full time employee (FTE) is assumed to work 2080 hours per year.

[27] 20 year period, 3.0% discount rate, $4.025/W capital cost, O&M of $19/kW/yr. PV costs $4.6/W installed. Added to this is $1.15/W for the parking capony structure. We have then assumed that the 30% tax credit would apply to these projects, giving a total installed cost of $4.025/W

Table 29: ROM Number Full Time Jobs Created

Location	Jobs-Construction/ Installation Period # FTE/yr	Jobs- During Operating Years # FTE/yr	Jobs over Lifetime # FTE/yr
California total	4,800	60	6,000

Table 30 and Table 31 present the estimated local and total costs.

Table 30: ROM Local Costs

Location	Construction & Installation Costs $M/lifetime	Annual Operational Expenses $M/yr	Lifetime (20 yr) Costs $M/lifetime
California total	340	4	420

Table 31: Estimated Total Costs

Location	Construction & Installation Costs $M/lifetime	Annual Operational Expenses $M/yr	Lifetime (20 yr) Costs $M/lifetime
California total	510	60	1,700

Financial Benefits (Customer Savings)

For calculations of customer savings, a retail price of $0.1789/kWh resulting in a levilized cost of $0.24/kWh was used. For the PV installations, a base installed system cost of $4.025/W resulting a levelized cost of energy for installed PV of $0.191/kWh[28] was used. System lifetime was assumed to be 20 years with a utility price escalator of 3% per year and 0% for PV production. The ROM estimated customer savings are presented in Table 13.

[28] 20 year period, 3.0% discount rate, $4.025/W capital cost, O&M of $19/kW/yr

Table 32: ROM Estimated Customer Savings

Location	Electricity Lifetime Savings with 3% Utility Price Escalation $M/lifetime
California total	180

Caltrans Past Work

Following on from Caltrans initial studies, Caltrans selected six of the best sites and developed RFP's to allow developers to bid on the sites to develop them. The RFPs were issued to the market and the response was limited. To date the reason that Caltrans does not have any PV installed in the right of ways is primarily an economic decision in that it is cheaper to develop PV elsewhere at the current time.

Variables that impact economic feasibility of PV at Caltrans sites include (but are not limited to): system cost, interconnection cost, incentives, acres under PV panels per megawatt of direct current, and power sales price.   New technologies that increase the efficiency or amount of power generated (solar panels produce more power per acre than current technologies) or changes in the economic factors (e.g. the cost of power increases, the cost of solar panels decreases) may result in sites becoming viable for PV development subject to Caltrans' safety and operational constraints.

CHAPTER 5: Conclusion

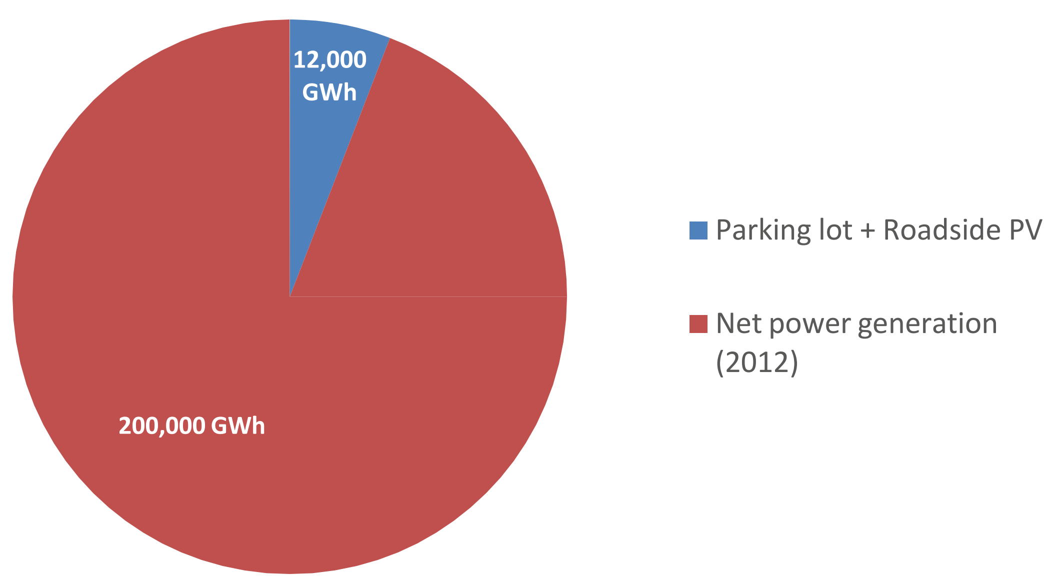
Implementation of CIRE projects in California has many potential benefits to the state. Table 33 summarizes the estimated energy savings, GHG emissions reduction, and job creation possible through implementation of parking lot PV, district thermal systems, and roadside PV.

Table 33: Summary of Potential Benefits for All the Implemented Projects

Project	Electricity savings (GWh/lifetime)	Gas savings (therms/lifetime)	GHG reduction (MT CO_2e)	Jobs created
Parking lot PV	222,000	-	51,753,000	395,000
District thermal	-100	11,330,000	967,500	-
Roadside PV	3,600	-	830,000	6,300

The potential power generation from all implemented PV projects corresponds to approximately 6% of the total annual electricity generation in California, illustrated in Figure 9.

Figure 9: Comparison of Potential Annual Electricity Generation from PV and the Total Annual Electricity Generation in California (2012)[29]



[29] EIA, "California Electricity Profile 2012", last updated May 1. 2014, http://www.eia.gov/electricity/state/California/

GLOSSARY

Term	Definition
CH_4	methane
CIRE	community integrated renewable energy
CO_2	carbon dioxide
DEF	district energy feasibility
CRZ	clear recovery zone
FTE	full time employee
GHG	greenhouse gas
JEDI	jobs and economic development impact
MT	metric tons
N_2O	nitrous oxide
NO_X	mono-nitrogen oxides NO and NO2 (nitric oxide and nitrogen dioxide)
O&M	operation and maintenance
PV	photovoltaic
ROM	rough order of magnitude
SO_2	sulfur dioxide

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APPENDIX A: District Thermal Assumptions

Number of Staff

San Francisco Downtown Buildings	
Max ft^2	84,621,771
Average Building Size (ft^2)	400,000
# buildings	212

Operations		Baseline FTEs				District Energy FTEs		
Shift		Day	Evening	Night		Day	Evening	Night
Control room		106	53	53		4	3	3
Daytime support		106	-	-		4	-	-
Admin, Economics, Marketing		-	-	-		4	-	-
Total		212	53	53		16	3	3
Maintenance		**Baseline FTEs**				**District Energy FTEs**		
Distribution		-				3		
Boilers/Heating		35				3		
Chiller/Cooling Towers		35				3		
Controls, Aux, Misc.		-				3		
Total		71				15		
O&M Cost		**Baseline Costs**				**District Energy Costs**		
Labor cost		120,000	$/FTE/year			120,000	$/FTE/year	
Total FTEs		388	FTEs/year			37	FTEs/year	
Total salary cost		**47**	**$M/year**			**4**	**$M/year**	

Water savings (result from DEF tool)

Location	Water MGal/yr
San Francisco	118
Los Angeles	33
Sacramento	16
San Diego	1
San Jose	8
Cities Total	176

APPENDIX G:
Task 3A: Community Energy and Enabling Technologies Use Case - Electricity

Energy Research and Development Division
FINAL PROJECT REPORT

COMMUNITY INTEGRATED RENEWABLE ENERGY PROJECT

Task 3A: Community Energy and Enabling Technologies Use Case - Electricity

Prepared for: California Energy Commission
Prepared by: Arup, for the San Francisco Department of Environment

ARUP

MARCH 2014
CEC-500-2014-MAR

CHAPTER 1: Introduction

1.1 Project Description

The Community Integrated Renewable Energy (CIRE) Project will assess the feasibility of community energy, district heating and cooling, renewable electricity, storage and energy recovery, demand response, and microgrid distribution technology to serve members of a community with their energy needs.

The CIRE Project consists of the following tasks and subject areas:

- Task 1: Administrative and Reporting
- Task 2: Distributed Generation Connected to the Electricity Network
- Task 3: Community Generation and Enabling Technologies
- Task 4: Energy Storage and Generation
- Task 5: District Thermal Energy Concept

This report provides our preliminary findings for Task 3A: Community Generation and Enabling Technologies.

The goal of this task was to engage community members and stakeholders in order to understand their desires and needs of CIRE systems via an interactive workshop and then draw insights from the workshop results.[1]The scenarios, organized into two broad case study areas, are listed below:

- community energy
  - photovoltaic (PV) canopy on a large parking garage
  - leasing space within a commercial building for community energy
  - using public road infrastructure for community energy
  - community wind energy
- grid separation enabling technologies[2]
  - individual commercial property owners able to separate from the grid
  - a community able to separate from the grid
  - powering critical community infrastructure during a 72-hour outage
  - a more resilient transit system

[1] The CIRE use case workshop was held at the SPUR offices at 654 Mission St, San Francisco, CA 94105 on the 27th January 2014 from 11.30am – 2.30pm.

[2] CIRE projects would normally operate in grid connected mode, only operating independently of the grid during outages.

The desired outcomes of the workshop were to engage stakeholders and collect feedback on the below challenges and opportunities:

Community Energy

- quantify baseline conditions
    - existing generation within the study area
    - current planned generation on new developments
    - the current and future developments and their respective power needs
- market and locational needs
    - the requirements for local generation/storage and where best this may be sited
    - defining the bounds of developments to be served by new generation assets
- ownership and regulation
    - the ownership and operation of new assets
    - how the distributed energy resources (DER)/storage are distributed to all the stakeholders
    - how this can be achieved with the current regulatory framework?

Enabling Technologies

- baseline conditions
    - limitations of the existing infrastructure
- market and locational need
    - whether the community system can continue to generate energy when there is a utility outage
    - whether the community system can separate from and reconnect with the electrical grid in a planned and unplanned manner successfully
- system functions
    - what an ideal system would look like
    - technology options
    - ownership of the assets

1.2 Attendees

The workshop was attended by 38 people from a diverse cross section of interested stakeholders. At the workshop there was attendance from:

- architects
- building owners
- construction companies
- developers
- economists
- energy companies
- engineers
- environmental consultants
- independent consultants
- planners
- real estate agents
- regulators
- technology companies
- technology providers
- transportation agencies
- universities
- utilities (investor-owned and municipal)

For a complete list of workshop attendees, please refer to Appendix B.

1.3 Workshop Structure

The workshop was structured to convene a diverse group of stakeholders within an umbrella of common interest.

The workshop discussions were guided by a series of questions which can be found in Appendix A.

Breakout groups were identified based on a suitable mix of expertise and interest. Each breakout group developed a CIRE scenario suitable to the case community. Each breakout group was asked to score their scenario on a scale of 1 to 10 using the scoring guide below:

- Use of community space: (10 = good use, 1 = bad)
- Fulfilling an energy need: (10 = great need, 1 = no need)
- Barriers: (10 = none, 1 = significant)

Supplemental analysis has been completed following the workshop in order to expand on key themes that emerged. Specifically, the supplemental analysis consisted of:

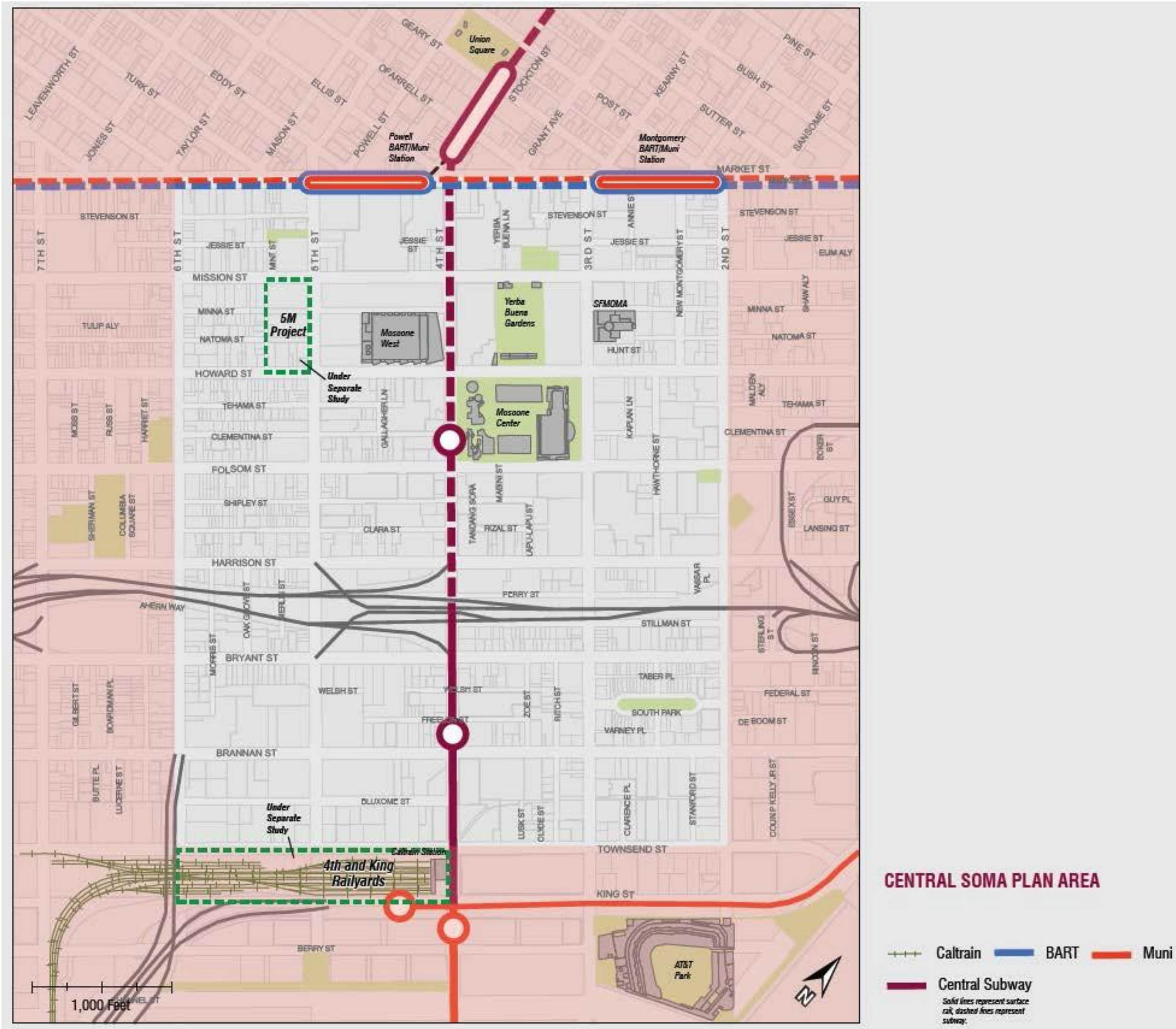
- Quantifying Central SoMa's parking garage PV potential
- Providing an economic value story for district thermal energy in Central SoMa
- Discussing integrated renewable energy potential with the California Department of Transportation (Caltrans)

1.4 Central SoMa Introduction

In San Francisco, 56% of greenhouse gas emissions are associated with lighting, heating, and cooling buildings. The City and County of San Francisco (CCSF) is committed to developing and implementing aggressive and diversified approaches to reducing these emissions while continuing to absorb anticipated regional population growth. One such approach is to plan carbon-free community-scale energy resources locally and regionally. Another is to increase jobs and housing in transit-oriented neighborhoods.

Central SoMa (South of Market) is a dense, transit-rich area of San Francisco that extends from Second Street to Sixth Street and from Market Street to Townsend Street in the city's South of Market area. The area has been identified as a priority development area by the Planning Department, and is the subject of a significant rezoning effort that encourages sustainable growth and creates substantial opportunities to align energy, transportation, water, and waste infrastructure systems. In addition to identifying the renewable energy resources and enabling technologies that could be appropriate for this district, the CIRE Project will identify ways CCSF can advance community-scale energy in this neighborhood. These efforts include providing a strategy to coordinate multiple public and private interests, including identification of all key institutional stakeholders and relevant regulatory frameworks.

Figure 1: San Francisco Central SoMa



Source: City and County of San Francisco, Planning Department

With the addition of the Central Subway along and under Fourth Street (under construction and scheduled to begin operation in 2018), undeveloped or underdeveloped parcels in the transit corridor offer a major development opportunity. CCSF anticipates approximately 12,000 new housing units and 35,000 jobs in this area. The Central SoMa Plan, released in draft in April 2013, proposes rezoning this area for dense, transit-oriented, mixed-use growth and provides opportunities to capitalize on rezoning to incorporate district-level energy infrastructure.

In addition to providing local energy, creating CIRE projects will greatly enhance the resiliency of Central SoMa. The ability to generate power and provide local energy is essential for both the immediate and long-term recovery from a large earthquake or similar disaster.

The Central SoMa CIRE Project has the potential to inform similar planning efforts in other parts of the state, particularly those with new development areas, major infrastructure projects, or significant revitalization planned, as well as existing neighborhoods.

1.5 Central SoMa Baseline Conditions

Building developers in Central SoMa are not actively planning to install significant amounts of renewable generation as part of their current development plans. Drivers of the limited renewable energy under consideration have primarily been linked to obtaining Leadership in Energy & Environmental Design (LEED) credits. The lack of renewable energy generation beyond this has often been an economic decision. In addition to the financial decisions, not all developers were aware of the various new ways in which generation can be shared within the existing regulatory framework and these methods are identified within this report.

In November 2013 the City and County of San Francisco (CCSF) produced an eco-district task force recommendations report for Central SoMa. (Central SoMa eco-district Task Force Reccomendations, 2013)

In terms of the task force's relationship to the CIRE project, the report made a key energy recommendation that a Net Zero Carbon/Energy District should be established in Central SoMa. In order to achieve this recommendation, the task force report identifies four implementation strategies:

- Prioritize energy efficiency in existing and new developments
- Encourage Community-Scale Clean Energy Systems in Areas with Intensive Infill Capacity and Anticipated Growth
- Develop Incentives to Encourage the Implementation of Community-Scale Clean Energy Projects
- Explore the potential of renewable energy generation and procurement

The existing renewable energy capacity in Central SoMa was assessed in the Task Force report and the results presented in the table below:

Table 1: Central SoMa Baseline Energy Conditions

Assessed Item	Baseline Condition
Commercial Solar Installations	There are 49 commercial solar installations, totaling 1,550 kW, in the two zip codes that are part of Central SoMa (out of 202 commercial installations across the entire city); the number located in Central SoMa is limited due to the likelihood of shading from tall and mixed building heights, as well as the location of PG&E's downtown mesh network which limits ability to interconnect solar to the distribution grid in the northern half of Central SoMa. Mitigation measure for interconnecting generation in Central SoMa's mesh network were discussed in the Task 2 reports.
Residential Solar Installations	There are 201 solar residential installations, totaling 1,046kW, on homes in the two zip codes that are part of Central SoMa (out of 3,524 in the entire city, totaling 10,360kW); this number in Central SoMa itself is likely small due to the lower number of single-family homes in the district compared to other neighborhoods, as well as the likelihood of shading from tall and mixed building heights, and the presence of PG&E's downtown mesh network which limits ability to interconnect solar to the distribution grid in the northern half of Central SoMa. Most of the residential installations are thus concentrated in the southern half of SoMa.

Source: City and County of San Francisco, Planning Department

Within the April 2013 Central SoMa plan the CCSF have estimated that there is potential for 11,715 residential units to be constructed and 9,391,145 square feet of commercial building space to be developed in the area.

Figure 2: The Central SoMa 2013 Plan Growth Potential

Source: City and County of San Francisco, Planning Department

A typical residential unit in the San Francisco climate zone will consume 5,628kWh (Maximilian & Aroonruengsawat, 2012) of electricity per pear. This multiplied by the number of residential units (11,715) and divided by the hours in the year (8760) results in the average increase in residential electricity use in Central SoMa of 7.5MW.

Reviewing previously constructed buildings[3] designed by Arup in California, the average electricity demand per square foot of commercial space has been calculated at 3.5W/sq.ft. Multiplying this by the growth potential in Central SoMa (9,391,145) results in a potential average commercial energy demand of 33MW.

1.6 Community Integrated Renewable Energy

California leads the country in the deployment of renewable generation. California law requires state utilities to procure 33% of their electricity needs from eligible renewable resources by 2020. This policy is called the Renewable Portfolio Standard (RPS)[4].

As a next step aimed at raising even further the State's ambitious renewable energy targets, Governor Jerry Brown has called for 12,000 MW of distributed renewable power to be generated by projects sized no larger than 20 MWs.

While the CEC has been tasked to work on how this target might be allocated amongst various programs and geographic or utility areas, it is broadly expected to include MWs from existing rooftop and ground mount programs, e.g., the California Solar Initiative, Renewable Auction Mechanism, Feed-in Tariffs and general renewable solicitations, etc.

To put the 12,000MW number into perspective, the California Solar Initiative (designed to support installation of solar PV systems under 1MW) has a goal of 1,940MW of installed capacity by 2016 and has currently reached the 1,659MW installed mark via approximately 160,000 installations since the program's launch in 2007 (*Peterson, 2013*). This 1,940MW target does not include publically owned utilities (which the 12,000MW target will apply to), but serves as a useful reference to the amount of renewable energy connections that could be required for small renewable energy systems.

In the context of this report, *local renewable power* is defined as generation installed on the distribution network so that benefits are gained locally. Such benefits include reduced system losses, energy security, deferred need for transmission lines and increased renewable energy content. Often these schemes are installed right at the load point, maximizing these benefits. The projects are typically sized from 1kW to 20MW and can be technologies such as photovoltaics, small wind, and biogas fuel cells.

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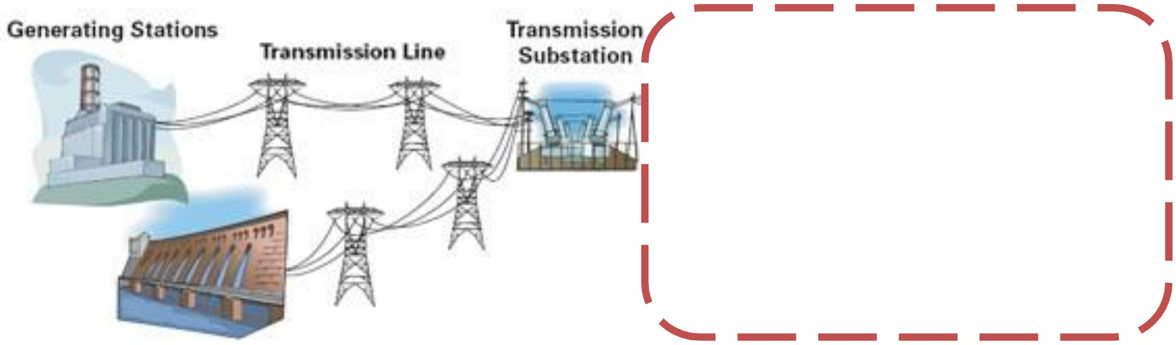
[3] Building types include commercial office space, museums, performance halls, laboratories, libraries and schools.

[4] Established in 2002 under Senate Bill (SB) 1078, accelerated in 2006 under SB 107 and expanded in 2011 under SB 2.

Figure 3: Location of CIRE Projects in the Electric System



Source: Southern California Edison

Local community generation drastically shortens the distance between the location where energy is generated and the site where it is being used. This reduces the need for high voltage transmission infrastructure upgrades, as well as reduces the amount of energy being lost through transmission from generation source to customer site. The reduced reliance on large, centralized, combustion-based generation for energy needs will also lead to a significant reduction in carbon dioxide emissions.

In the context of this report, *enabling technology* is a technology that, should the grid power be lost due to an outage, will allow the community generation to continue to operate and provide power to the loads until the grid power is restored. The term 'Microgrid' describes this mode of operation. Microgrids are localized, integrated energy systems that supply power to communities of various sizes, from small residential clusters to providing the energy needs of a corporate campus. They consist of distributed energy resources (including photovoltaics (PV), fuel cells, combined heating and power (CHP) and wind), electricity storage (such as batteries or liquid air) and electrical loads operating as an autonomous grid. Microgrids act either in parallel to, or islanded from, the local electricity distribution network.[5]

Implementing CIRE projects will provide important advantages in California's drive for clean power — development of local resources, avoided costs of new intercity transmission or remote generation, additional consumer autonomy, greater resiliency and reduced greenhouse gas emissions.

This report seeks stakeholder feedback to increasing community-based renewable energy systems and identifies enabling technologies (such as a microgrid) that would manage or facilitate renewable generation, distribution, and storage within a community.

Broad support for CIRE calls for new approaches and coalitions between consumers, community leaders, utilities, and power providers. These new approaches have to address the needs and desires of key stakeholders: utilities, consumers, businesses, and residents, along

[5] This report assumes that microgrids are *grid-connected* microgrids. They will only operate independently of the grid during times of grid outages.

with consideration of health and environmental factors. An influx of new local generation is likely to require revised utility business models as we transition toward a new paradigm for our electrical grid.

CHAPTER 2:
Community Generation Scenario 1 – Parking Garage PV

Construction of a PV canopy on a parking garage to offset the energy needs of neighboring properties

Figure 4: Central SoMa Parking Garage at 5th and Mission St.

Photo source: Google Inc.

2.1 Summary

Within this scenario a PV array is constructed on an existing or new build parking garage. The parking garage has a minor electrical load, thus its PV generation potential likely exceeds its load.

Using existing and new parking lots for CIRE generation is an excellent use of the space and has the potential to fulfill an energy need. Solar integrated with parking provides useful shading to parking spaces and does not impact on the long term operation of the parking facility. In order to fulfill an energy need, parking lots near load centers or with high energy demands would be required to be selected to allow this requirement to be met.

Regulatory barriers are significant to the adoption of this scenario under certain conditions. When all of the energy can be used on site, the regulatory barriers are removed. Sharing generation to buildings under the same ownership has minor regulatory barriers due to the fact that the regulatory framework is not yet fully in place. Selling the generation to other buildings is very constrained and this scenario would have to address significant regulatory barriers to become feasible.

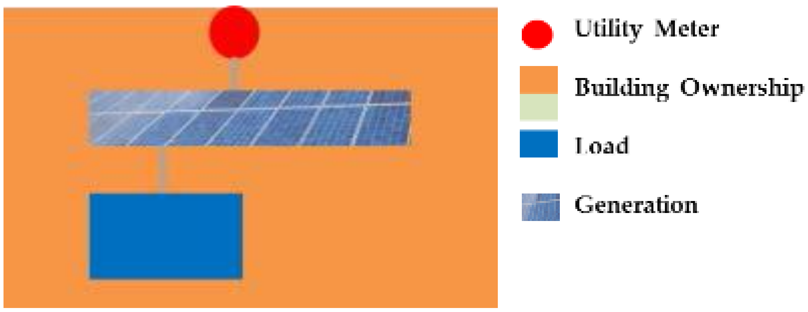
Post workshop work has presented a scenario to enable the use of the generated electricity on the parking garage site.

2.2 Workshop Discussion and Insights

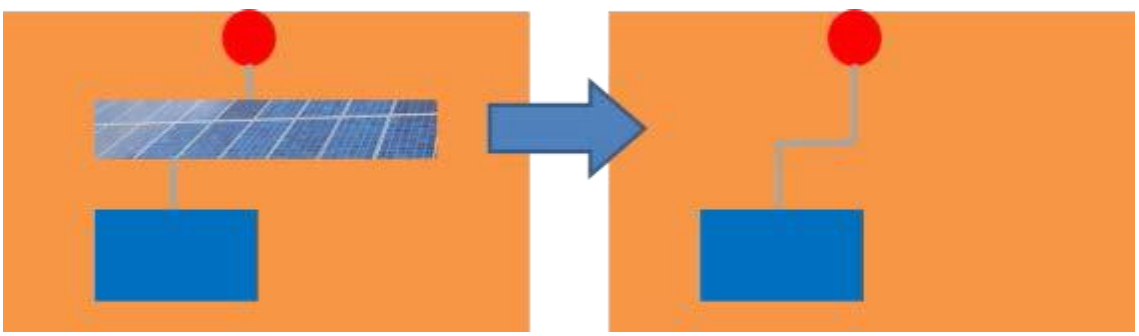
When asked the question to consider if this is a suitable location for community shared energy, every member of the workshop group believed that the location is an excellent choice for renewable energy. The location is unobtrusive, sites can be selected to ensure that load centers are served and the PV canopies provide useful shading to vehicles.

Three ownership structures were analyzed for this scenario:

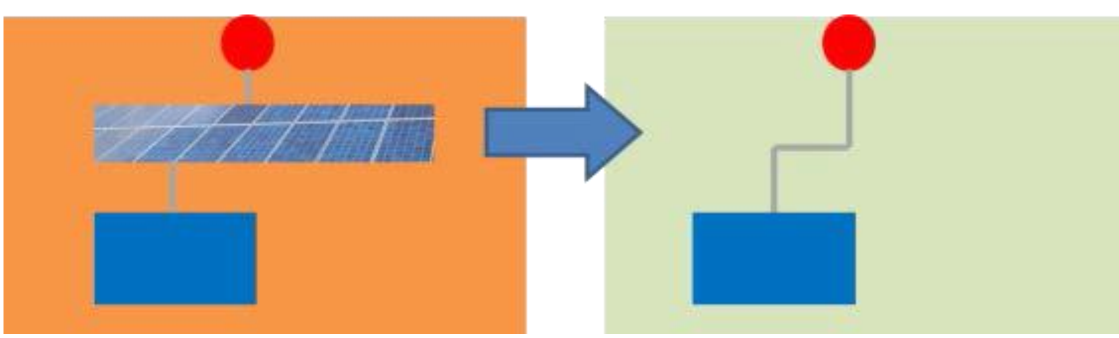
1. Utilize all of the generation on-site



2. Share the generation with other buildings under the same ownership



3. Share the generation with other buildings under differing ownership



2.2.1 Generation Used on-site

Under a Net Energy Metering[6] (NEM) arrangement, the capacity of the PV array is typically sized to meet the annual electricity consumption of the facility to which it is interconnected. With a parking structure, traditionally there is little in the way of electrical load.

Without a significant interconnected electrical load, the size of the PV array that can be installed on parking structures is very low compared to the available space.

Reviewing a case study developed during the design of a National Renewable Energy Laboratory (NREL) parking garage (NREL, 2012). NREL set an annual energy goal[7] of 51 kWh/parking stall/year for the construction team[8]. This is a low energy demand and a typical 1,000 space parking lot with the same installed energy efficiency measures would have an annual energy consumption of approximately 51MWh. Sizing a PV generator to match this load would result in a system with a capacity of around 36kW[9].

Due to the low electrical load of parking garages, better paths to stimulate projects of this type are required to create more revenue streams for the garage owner. Some methods to stimulate parking garage PV ay include:

- Integrating with EV charging (standard and fast charge)
- Integrated energy storage
- Favorable planning processes for garages which incorporate renewables

Using existing and new parking lots for CIRE generation is an excellent use of the space. Solar integrated with parking provides useful shading to parking spaces and does not impact on the long term operation of the parking facility.

A typical parking lot has a small electrical load and this scenario does not address an immediate energy need. Should the parking garage have a higher than average electrical demand, such as by having integrated EV charging then the energy need increases significantly.

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[6] Customers who install generation facilities (1 MW or less) to serve all or a portion of onsite electricity needs are eligible for California's net energy metering program. NEM allows a customer-generator to receive a financial credit for power generated by their onsite system and fed back to the utility. The credit is used to offset the customer's electricity bill at the full retail rate. NEM allows the customer to size their generation to meet their annual load instead of an instantaneous demand and use the grid as a storage device for this energy when it is not needed.

[7] The goal encompasses lighting, security, fans, parking management, and parasitic loads, but does not include EV charging. The architectural layout originated and was refined based on low energy and sustainability concepts such as day lighting, natural ventilation, efficient loading and unloading schemes, and preferred parking organization.

[8] The final measured result of the constructed parking garage used less energy than specified (49 kWh)

[9] South facing, roof mounted system based in the San Francisco Area where a 1kW array will typically generate 1,420kWh/y.

When all of the energy can be used on site, there are no regulatory barriers that cannot be addressed. Further analysis work has revealed alternative strategies to enable the use of the generated electricity on the parking garage site and this is presented within this chapter.

The scenario scores are listed in the table below.

Table 2: Scenario 1 – Use Generation On-site

Criteria	Score
Use of community space	10
Fulfill an energy need	5
Regulatory barriers	8

2.2.2 Generation shared with other buildings under the same ownership

Common ownership of local buildings would allow generation to be shared under a common energy metering tariff.

Arup have provided extensive commentary around the regulations in California regarding the sale and distribution of electricity in the CEC report: CEC-500-2014-FEB, which was produced under the Task 2 deliverable. CIRE model 2 within this report addresses the issue of distributing power to other buildings under common ownership.

The solution to allow energy generation sharing is contained within the implementation of Senate Bill (SB) 546[10]. Known as "aggregated NEM," SB 546 allows NEM generation to be shared across a customer's properties through virtual net metering. Under aggregated NEM the maximum rating of the generator has been set at 1MW and this limit is not expected to constrain the PV generation on parking garages[11].

Within the CEC-500-2014-FEB report, Arup also investigated an innovative tariff option that is proposed in Con Edison's electricity sales area and we recommended that a similar tariff be considered for California. The new Con Edison electric tariff allows customers that have utility service accounts at multiple buildings (that may be on more than one parcel of land) to centralize their generation at one site e.g. a parking garage with PV. The utility's wires are then used to distribute the generator's output and the generation is credited to eligible customer's meters. The utility then makes a fair charge for the use of their distribution assets. Unlike aggregated NEM the limit for generation scale in this application is 20MW.

In order to fulfill an energy need, a parking lot owner with other local buildings would need to be selected in order to utilize all of the energy generation.

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[10] Implementation date on SB 546 is expected in 2014

[11] Only one parking lot in the Central SoMa study area has a PV generating potential in excess of 1MW.

Sharing generation to buildings under the same ownership has minor regulatory barriers due to the fact that the regulatory framework is not yet fully in place

The scenario scores are listed in the table below.

Table 3: Scenario 1 – Buildings with Common Ownership

Criteria	Score
Use of community space	10
Fulfill an energy need	7
Regulatory barriers	6

2.2.3 Generation shared with other buildings under differing ownership

Within the current regulatory framework, the public utilities codes define the requirements regarding the sale of electricity.

Leveraging the previous work Arup has conducted for the CEC (Report CEC-500-2014-FEB). Under CIRE model 3, Arup concluded that a generation owner will be defined as an electrical corporation or public utility if the owner produces and distributes electricity for sale to parties other than the generation owner and/or the tenants of the individual building or property where the generation is located.

There are exclusions to the above statement. Within section 218 of the public utilities code, the code makes it clear that the generator owner is not defined as an electric corporation if the generation station uses cogeneration or non-conventional sources[12] to produce electricity, unless the electricity is sold to more than two adjoining properties, or the properties that it is sold to are across a public right-of-way.

Therefore a parking garage owner could sell the electricity to adjacent properties (maximum of two) providing these properties were not separated by a public right of way. Knowledge of these regulations, complexity, cost and lack of regulatory experience are expected to be a significant barrier to the uptake of such solutions by garage owners.

Regulatory barriers were seen as significant to the adoption of this scenario. Selling the generation to more than two buildings on the same land parcel is very constrained and this scenario would have to address significant regulatory barriers to become feasible.

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[12] Conventional energy resources are electric generation facilities or technologies that have been in practical use for a long time or which represent the majority of generation resources in use (i.e., coal, natural-gas, nuclear). At the time of writing non-conventional sources of generation include renewable generation sources such as solar, wind and bio-gas fuel cells.

The scenario scores are listed in the table below.

Table 4: Scenario 1 – Buildings with Differing Ownership

Criteria	Score
Use of community space	10
Fulfill an energy need	6
Regulatory barriers	3

Another more feasible solution within the existing regulatory framework is contained within SB 43. SB 43 allows Californians to have up to 100% of their electricity supplied from off-site renewable sources. SB 43 initially requires utilities make available 600MW of generation for customers to purchase renewable bill credits. 100MW of the allocation is set aside for projects of less than 1MW in size, which is particularly applicable to CIRE projects. The 100MW of smaller generation projects are proposed to be built in areas identified as having significant environmental and income disadvantages. Utilities will solicit bids from third party generation suppliers who will then build and operate the generation assets, selling the utility the clean power via a Power Purchase Agreement (PPA). Discussions with PG&E revealed that providing the parking garage met the criteria of the smaller 1MW projects, such a project could be brought to PG&E for consideration. The parking garage owner would likely receive a lease payment from the project developer as part of the contractual arrangements.

2.3 Further Analysis

The work undertaken at San Diego Zoo provides an excellent case study to what can be achieved in a parking garage to maximize renewable generation sizing, while consuming, over a period, all of the electricity generated within a single site. The San Diego Zoo project has installed a solar photovoltaic canopy that will charge EVs in the Zoo parking lot. One of the first of its kind in California, the project uses solar energy to directly charge plug-in EVs, store solar power for future use, and provide renewable energy to the surrounding community.

Figure 5: San Diego Zoo PV Canopy

Photo source: San Diego Gas and Electric

The San Diego Zoo project consists of the following elements.

- 10 stand-alone solar canopies, each 10′ x 9′ and rated at 9kW
- 5 EV chargers
- 50 cars can park under the canopies for shade
- 100 kilowatts of battery storage

A Nissan Leaf is a 100% pure electric car. The 2013 model has a 24 kWh lithium ion battery. According to the US Environmental Protection Agency (EPA)[13]; the 2013 Leaf has an electricity consumption of 29 kWh/100 miles. The range of the car on a single charge is 75 miles and using a 240V charger will charge from empty to full in 5 hours (22kWh of electricity). Fast Direct Current (DC) charging is available and will typically charge the car in 30 minutes.

13 http://www.fueleconomy.gov/feg/Find.do?action=sbs&id=33558&id=32154&id=30979

Within this section Arup have studied the PV generation potential in Central SoMa. The case study assesses the following situation:

- Assess all parking lots in Central SoMa
- Generation to be constructed to provide parking shading
- All generation to be used on site
- EV charging is the primary load

The assessment does not take into account:

- Costs
- Existing structural strength of parking lots
- Structural modifications
- Detailed shading calculations

In order to avoid regulatory issues, the garage owner would pay for the electricity used to charge the cars and not sell electricity. Revenue would be generated by the garage owner by receiving sufficient payment for EV parking spaces and charging the EV cars for free.

Arup have assumed that the PV installed on a parking structure will have an average capacity of 9.3W[14]/sq.ft to allow for the safe operation of the parking lot and provide free space in-between parking stalls to allow vehicle movement. A typical high efficiency roof mount solar array will have a density of around 15W/sq.ft.

[14] This value was calculated from an existing installation. The Schletter Solar Plant in Germany has a 500kW Parking Lot PV array. This array takes 53,770 sq.ft of parking space including access lanes.

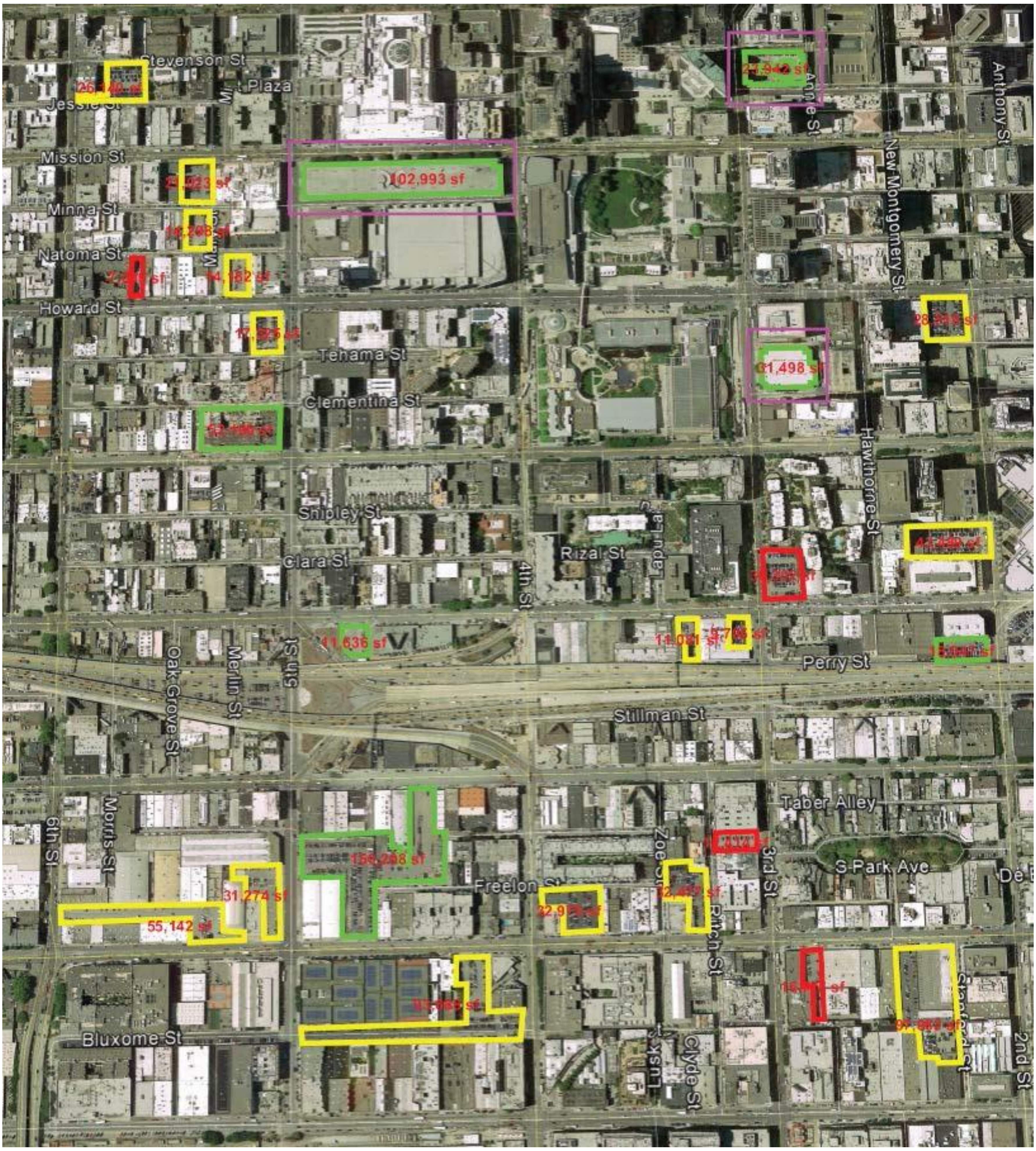
The 500kW Schletter Solar Carport Installation is shown below and provides a real life use-case that has been applied to Central SoMa.

Figure 6: 500kW Schletter Solar Carport Installation

Source: Schletter Solar Mounting Systems - Solar Carport Systems

Each parking lot area in Central SoMa, measured in square feet, was estimated using on-line mapping to produce the below figure.

Figure 7: Parking Lot Areas in Central SoMa



Obstructions
- Minimal
- Slight
- Significant
- Roof Top Parking

To calculate the PV potential in Central SoMa, 9.3W/sq.ft was multiplied by the identified parking lot's area. A generation factor of 1kW installed capacity = 1,420kWh/y[15] was then used to determine the annual energy production of the PV array. Shading calculations were not performed. However, an estimation was made of shading effects based on the presence of tall buildings to the south of some of the identified parking lots. The shading factors that were used in the assessment are listed below:

- Minimal = 1
- Slight = 0.875
- Significant = 0.65

Finally in order to ensure that all of the generated energy could be used on site, a calculation of the EV charging load was made. It has been assumed that within a 24 hour period there will be 3 EV charging events per space, filling the EV from empty to full. Over the course of the year it is assumed that EVs will only charge on workdays.[16]

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[15] Using a San Francisco Airport Weather file, 1kW of installed PV will produce approximately 1,420kWh/y of electricity in an unshaded area.

[16] A Nissan Leaf consumes 22kWh of electricity per charge. 3 charges per day for 260 days per year means each EV charging station will have an annual electricity consumption of 17,160kWh/y.

The results of the assessment are provided below:

Table 5: Central SoMa PV and EV Charging Potential

Location	Type	Obstructions	Total Area [ft^2]	Generation [kWh/yr]	Array Size [kW]	Minimum Number of EV Spaces
1	Ground	Slight	26,140	302,054	243	18
2	Roof Top	Minimal	23,942	316,178	223	18
3	Ground	Slight	21,023	242,926	196	14
4	Roof Top	Minimal	102,993	1,360,126	958	79
5	Ground	Minimal	14,298	188,819	133	11
6	Ground	Significant	7,099	60,937	66	4
7	Ground	Slight	14,182	163,877	132	10
8	Ground	Slight	17,325	200,195	161	12
9	Roof Top	Minimal	31,498	415,963	293	24
10	Ground	Slight	28,519	329,544	265	19
11	Ground	Minimal	52,100	688,033	485	40
12	Ground	Minimal	11,636	153,665	108	9
13	Ground	Slight	11,081	128,044	103	7
14	Ground	Slight	9,705	112,144	90	7
15	Ground	Significant	3,302	28,344	31	2
16	Ground	Slight	43,489	502,526	404	29
17	Ground	Minimal	18,047	238,329	168	14
18	Ground	Slight	55,142	637,180	513	37
19	Ground	Slight	31,274	361,379	291	21
20	Ground	Minimal	150,208	1,983,647	1,397	116
21	Ground	Slight	32,978	381,069	307	22
22	Ground	Slight	32,477	375,280	302	22
23	Ground	Significant	1,414	12,138	13	1
24	Ground	Slight	93,688	1,082,588	871	63
25	Ground	Significant	16,776	144,004	156	8
26	Ground	Slight	97,982	1,132,207	911	66
TOTALS			**948,318**	**11,541,193**	**8,819**	**673**

There is a significant opportunity to increase community renewable energy in Central SoMa with the installation of integrated PV and EV charging stations. Commercial parking lot PV installations have the opportunity to increase the commercial PV capacity in Central SoMa from 1.5MW to 8.8MW, a nearly six fold increase. The installation of clean, renewable energy will also be an enabler in the installation of a minimum of 673 new EV charging stations in the area.

In order to assess the likelihood of each project, a detailed feasibility and value proposition study would be required to be carried out at each site.

CHAPTER 3:
Community Generation Scenario 2 – Leasing space in a building

Leasing space on or in a commercial building (basement or roof) for community generation

Figure 8: Potential Leasable Spaces within Buildings for Energy Generation

Photo source: Arup.

3.1 Summary

Within this scenario a commercial building leases space for the installation of a generation asset. This may be roof space for a PV installation or space within a basement for a form of Combined Heat and Power (CHP) plant such as fuel cells. In general, buildings are assumed to be multi-tenant, and commercial, residential or mixed use.

Leasing space within a commercial building is an excellent use of the space and it fulfills an energy need. Leasing a portion of a basement space, taking up a single car parking space or utilizing a vacant roof space all are excellent uses of space in order to provide clean electricity generation. In order to fulfill an energy need the generated electricity would be required to be used either on the building or exported to an adjacent load center.

Regulatory barriers are significant to the adoption of this scenario under certain conditions. When all of the energy can be used on site, the regulatory barriers are removed. Selling the generation to other buildings (more than two and separated by a public right-of-way) is very constrained and this scenario would have to address significant regulatory barriers to become feasible.

There are also perceived liabilities of either hosting or connecting to power assets on a private building.

3.2 Workshop Discussion and Insights

In the development process, risk is always at the forefront of a developer and building owners mind. In relation to installing a generation asset in a building, some of the pertinent risks are identified below:

1. Who is the buyer and what are the contractual arrangements
2. Credit worthiness of buyer of electricity
3. Building upgrades and who bears the cost
4. Retrofit challenges

In additional to the identified risks, there are also barriers to the use of the generated electricity. In relation to installing a generation asset in a building, some of the pertinent barriers are identified below:

1. Sale and distribution of electricity
2. Capital and operational costs
3. Technical issues

Two ownership structures are presented:

1. Utilize all generation within the building
2. Share the generation with other buildings under differing ownership

Investigations have been undertaken to propose suitable delivery vehicles to enable generation to be installed within buildings while mitigating the risks and barriers that were highlighted during the workshop.

3.2.1 Utilize all generation within the building

Utilizing all of the generation within a multi-tenant residential or commercial building is feasible in California under the Virtual Net Metering (VNM) tariff.

Under VNM, a large (up to 1MW) renewable generation asset[17] is installed in a building and all of the power is metered and exported to the grid. The utility then automatically applies the credits from that electricity to the tenants in the building offsetting their electricity costs. This can allow the tenants to have renewable energy supplied to them directly from the building.

Under the terms of VNM, the building owner, operator or a third party can install the generation asset and contract with the utility for the exporting of the power and credits to the tenants.

There are many companies that provide VNM services to building owners and developers that remove all of the risk of construction and credit worthiness of electricity buyers. A company can be contracted to finance, own, install, operate and contract with the utility. A lease payment to the building developer / owner is then received for the used space that the generation occupies.

Leasing space, particularly roof space, within a commercial building is an excellent use of the space and it fulfills an energy need. Leasing a portion of a basement space, taking up a single car parking space or utilizing a vacant roof space all are excellent uses of space in order to provide clean electricity generation. Using all of the generation onsite via a direct connection to a centralized energy plant or to the building tenants ensures that here are no regulatory barriers. There is still the issue of liabilities and operation and maintenance to address. Such issues can be overcome with clear contractual arrangements with the owner and operator of the generating asset.

[17] Eligible technologies include: Biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation, digester gas, municipal solid waste conversion, landfill gas, ocean wave, ocean thermal or tidal current technologies.

The scenario scores are listed in the Table 6.

Table 6: Scenario 2 – Use Generation On-site

Criteria	Score
Use of community space	8
Fulfill an energy need	7
Regulatory barriers	6

3.2.2 Share the generation with buildings under differing ownership

As concluded in Scenario 1, sharing the generation with other buildings (more than two on a contiguous land parcel) is not possible under the current regulatory framework if the generation owner does not intend to become a regulated utility. There are alternatives to consider as concluded in Scenario 1 with the introduction of SB 43.

Another alternative model to allow available commercial building space to be leased was trialed by San Diego Gas and Electric (SDGE). SDGE has conducted research via its sustainable communities program that was recently closed to new projects. Under the sustainable communities project, SDGE worked with commercial buildings to create showcase energy efficient, sustainable projects that incorporated SDGE owned and operated renewable generation on customer's properties. SDGE connected the generation to their side of the meter and the generated electricity became wholesale power to SDGE. The customers continued to purchase power from the utility via a standard retail rate. The consumers who had generation installed at their property were paid a lease. A 100kW generation system would attract an annual lease payment of $1,700. The lease terms were 20 year leases with options for the customers to buy the generation asset at years 10 and 15. The SDGE trial was a success and installed over 4MW of clean generation in 40 projects. The scheme was not considered business as usual and the projects were installed during a research project with the permission of the Californian Public Utilities Commission (CPUC). The introduction of such schemes into 'business-as-usual' would give developers and building owners a risk free method of using their property space for generation while receiving an income from this space. The schemes were primary aimed at commercial properties and allowed the commercial property to obtain LEED[18] credits for the installed renewable generation.

[18] Leadership in Energy and Environmental Design

The scenario scores are listed in the table below.

Table 7: Scenario 2 – Share Generation with other Buildings

Criteria	Score
Use of community space	8
Fulfill an energy need	7
Regulatory barriers	2

3.3 Further Analysis

Table 8 summarizes the results from a preliminary indicative analysis comparing the building and community scale models for heating and cooling for future development as described in the Central Corridor Plan. The goal of this analysis was to test of the potential energy, spatial, capacity, and operations and maintenance (O&M) efficiencies associated with centralized heating and cooling.

Table 8: Scenario 2 – Share Generation with other Buildings

	Building-Based Heating & Cooling	District-Scale Heating & Cooling	Difference	%
Total Heating & Cooling Capital Costs	$550,000,000	$700,000,000	($150,000,000)	*(27%)*
Total In-Building Capital Costs	$550,000,000 (same as above)	$40,000,000	$510,000,000	*93%*
Installed Heating Capacity (MMBH)	700	600	100	*14%*
Installed Cooling Capacity (Tons)	66,000	51,000	15,000	*23%*
Annual Labor Costs	$40,000,000	$25,000,000	$15,000,000	*38%*
Plant Space Required in Buildings	140,000	50,000	90,000	*64%*
Amount of Roof Space Required	170,000	0	170,000	*100%*
Central Utility Plant Floor Plate	0	100,000	(100,000)	*(100%)*
Annual Energy (MWh)	300,000	220,000	80,000	*27%*
Annual Carbon (Tons)	71,000	57,000	14,000	*20%*

The analysis suggests that total capital costs will be the order of 25% - 30% higher for a community scale heating and cooling solution, due primarily to the large initial investment required for distribution. It should be noted that this goes hand in hand with a 90% - 95% capital cost reduction at the building level. This is because heating and cooling is produced outside of buildings in the community scale model, and thereby only costs for substations are needed inside buildings.

The analysis also suggests that installed capacity can be on the order of 10% - 25% lower at the community scale compared to the building scale. This is in part due to the centralization and therefore minimization of redundancy, but primarily due diversity which can be captured when buildings with peak loads occurring at different times are connected to a community heating and cooling system.

The community scale model also reduces costs associated with O&M. For the Central Corridor Plan, the analysis suggests that a reduction on the order of 35% - 40% can be expected. This reduction is due to the fact that at a building scale, there is a need for multiple O&M staff in each building, whereas at a community scale there are fewer pieces of larger, centralized, and often highly automated equipment, which results in a significant O&M staff reduction. This also creates the potential to have more specialized members of staff, who operate the plant more efficiently than typical building level staff, and who may be able to perform certain maintenance and overhaul tasks internally, shedding further maintenance contract costs.

Heating and cooling at a building scale takes up significant floor area within buildings in the form of mechanical, refrigeration, and boiler rooms, and roof area in the form of boiler flues and cooling towers. At a community scale, the energy production takes place outside of the buildings, freeing up these spaces within buildings for tenant amenities and/or lettable real estate. The community scale model does however require the construction of a central utility plant which requires space within the community. However, as the analysis suggests, an overall area reduction of around 50% can be expected for the heating and cooling functions if a community scale heating and cooling model in pursued for the Central Corridor.

Another benefit of a community scale model is the potential to reduce total energy production as well as associated carbon dioxide emissions. Centralization often results in improved efficiency through larger more efficient equipment, system integration, district-wide heat recovery opportunities, and sophisticated controls. These typically outweigh distribution efficiency losses in modern community scale systems. For the Central Corridor, the analysis suggests that the community scale heating and cooling model can reduce energy on the order of 30%, and carbon emissions on the order of 20%.

The following figures illustrate additional data generated as part of this analysis.

Figure 9: Average monthly total demand range

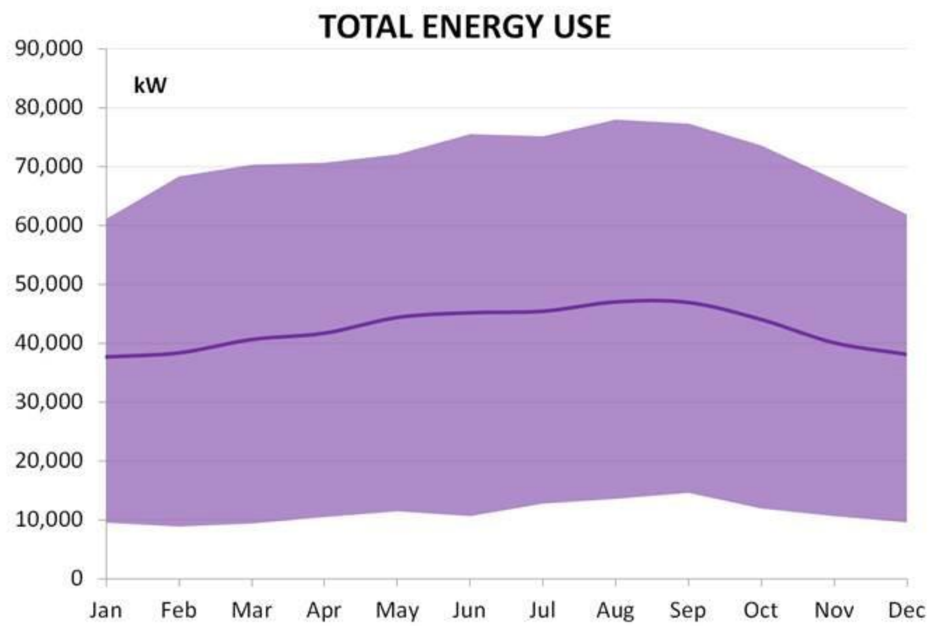


Figure 10: Average daily and monthly heating, cooling and electric demand ranges

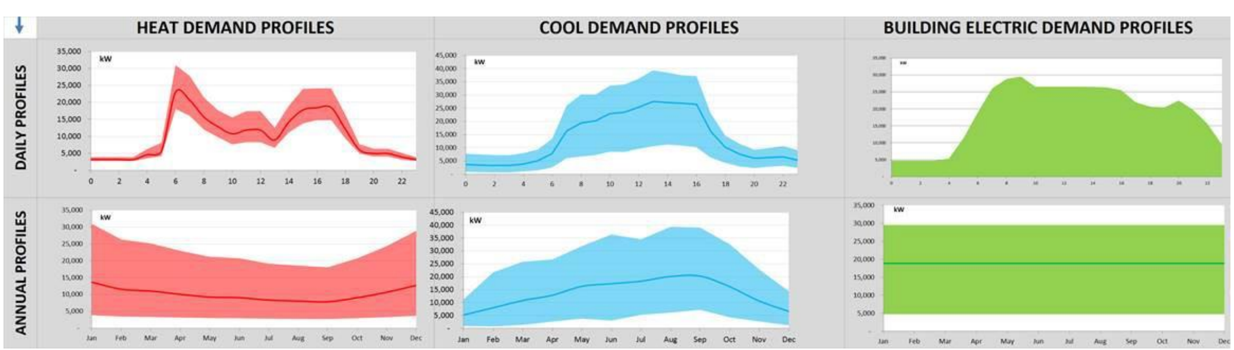
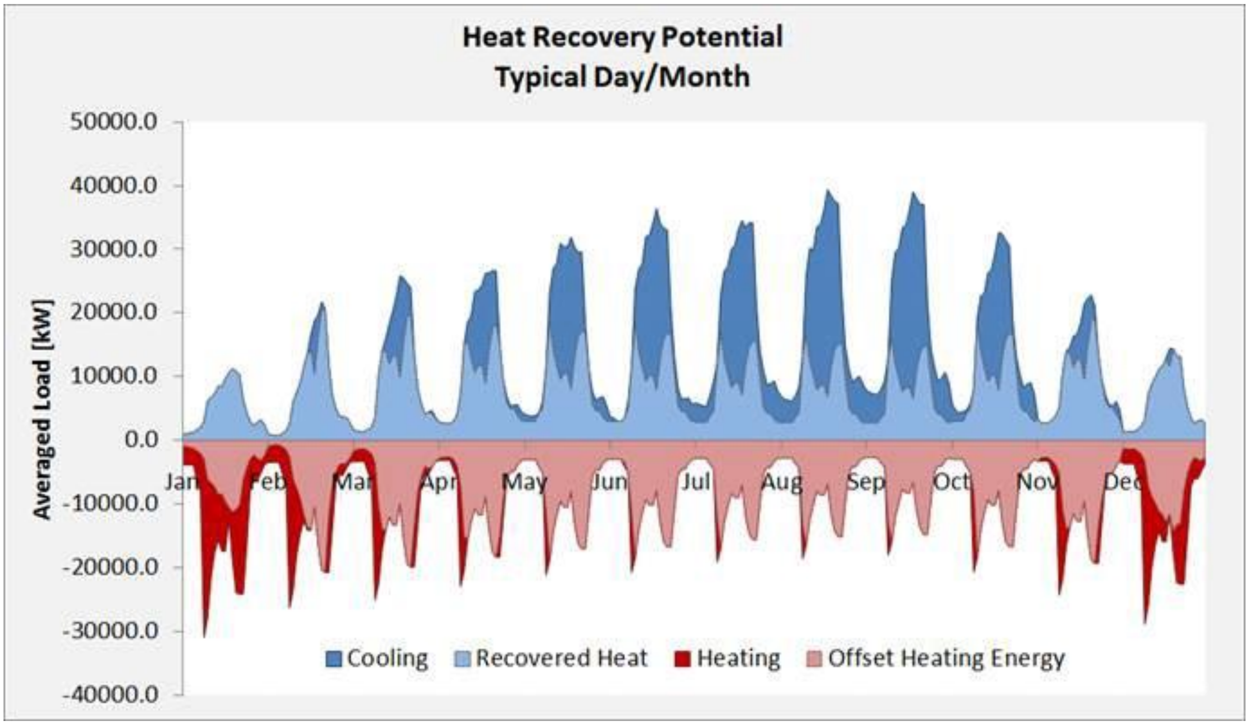


Figure 11: Typical monthly average simultaneous heating and cooling demand



Note: The analysis used the following key assumptions:

- Utility emission factor: 0.59 lb of Carbon/kWh, which is based on a 2035 date
- Blended energy rate: $0.12/kWh, which is based on 2014 rates

CHAPTER 4:
Community Generation Scenario 3 – Public Road Infrastructure

Using public road infrastructure for generation / energy storage (easement / integrated)

Figure 12: Integrated Renewables with Road Infrastructure

Photo sources: www.photovoltaik.eu (L), www.ralos.de (R)

4.1 Summary

Within this scenario renewable generation is installed integrated with, or in the easement space of public road infrastructure. There are many examples of this innovative approach in European countries and two in the USA.

Using existing and new road assets for CIRE generation is an excellent use of the space and it fulfills an energy need. Highway easements and airspace[19] are typically under-utilized spaces and with renewable generation can be turned into a revenue source for the State agency.

Caltrans were unable to attend the workshop so the content discussed at the workshop does not contain the views of Caltrans.

In order to fulfill an energy need, road infrastructure near load centers or with high energy needs (significant lighting demand, coupled with energy storage) would be required to be selected to allow this requirement to be met.

Regulatory barriers are a large barrier to the adoption of this scenario. In particular safety concerns presented the biggest barrier to adoption of utilizing this space. Additional barriers are in the sale and use of the generated electricity.

Post workshop work has included discussions with Caltrans and research of Caltrans studies where renewable assets were planned in Caltrans airspace. Post workshop work with Caltrans has revealed the following:

- Caltrans has actively studied renewable generation adjacent to road assets (at intersections). Due to primarily economic reasons, none of the sites are yet to be developed. Caltrans issued RFP's for developers to build on the sites, but the market did not respond favorably. Caltrans however are open to renewable generation in interchanges and are happy for others to develop these sites providing interchange safety clearances are maintained.
- Installing generation / energy storage in the airspace beneath freeway's / underpasses would not be permitted due to safety regulations.

4.2 Workshop Discussion and Insights

There are several key themes when looking to integrate renewable energy into the road infrastructure:

[19] The Airspace and Telecommunications Licensing Program, or simply Airspace, is part of the Real Property Services Branch within the Division of Right of Way. Traditionally, Airspace was that area under bridge structures and viaducts that could be used for other purposes. Hence the term Airspace. Airspace is responsible for leasing and managing those properties or sites held for a transportation purpose that can safely accommodate a secondary use. More simply put, Airspace leases specific areas within state highway right of way. Source: http://www.dot.ca.gov/hq/row/rps/airspace.htm

1. Possible Technologies
2. Ownership models
3. Risks and Barriers

4.2.1 Possible Technologies

Solar integrated with the road network was thought by the attendees at the workshop to be an ideal technology to integrate with Caltrans assets. This scenario has been implemented in European countries successfully and extensively and there are two examples in Oregon, USA.[20]

In Central SoMa, placement of PV panels would be required on the north side of the highway to avoid shading due to up zoning as part of the Central SoMa plan. A small scale pilot is recommended in order to demonstrate this integrated CIRE technology as this would be the first of a kind in California. An ideal location would be to place PV on an existing or new sound barrier.

There is another opportunity for CIRE integration with road infrastructure. This is to use the space below elevated highways (airspace) for generation uses and as EV parking lots. The space could be leased to a third party to install bio-gas CHP, fuel cell or other generating technology[21]. EV fleets (corporate or car share) would use the renewable energy to charge, similar to the parking lot analysis carried out in the previous scenario.

Other less mature technologies that could be integrated with the highway include piezotechnology on streets or highway lanes with high vehicle use to power local infrastructure such as signage.

4.2.2 Ownership

A transit agency would unlikely to want to own, operate, maintain and develop such generation projects. A third party developer would be preferred by transit agencies and this has been demonstrated within the existing USA investigations into integrated transit infrastructure and renewables.

A third party developer agreement would need to consider:

- Transit agency would want to receive lease payments
- Access agreements are important to ensure safety, O&M from road pollution, etc.
- Third party electricity off taker also needed
    - Caltrans have small onsite electricity needs, depending on location (e.g. for signage, lighting) and may be an ideal off taker
    - An adjacent property could be the off taker (could possibly occur without crossing public right of way and mitigating regulatory issues)

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[20] See Task 6 report for details of the work Caltrans has been performing in this area

[21] Discussions with Caltrans following this workshop has revealed that generation technology would pose a fire risk and would therefore not be permitted under the freeways. Caltrans does not permit generating technology under the freeways. EV's however may be permissible where the space under the freeway is already a parking lot.

- Could provide power to a Community Solar program or for a green power purchasing program provided by PG&E under SB 43.
- A utility can purchase the power which would be a typical arrangement

4.2.3 Risks and Barriers

The key to successful implementation of new of projects such as integrated energy is to remove the risks and barriers to development.

One of the key objectives for a transit agency is to ensure that their transit network is safe to operate. For road networks a key objective would be to ensure that there is no risk of any foreign objects from a CIRE project falling onto the road or causing an increase in traffic accidents and that existing safety setbacks are maintained. To learn from previous installations of this type of technology and conduct small scale trials is essential in order to remove the risks of this type of development.

The increased safety requirements and construction constraints are likely to make developments of this type more expensive than traditional solar projects. Without very careful site selection increased costs could make projects uneconomical.

The electricity regulatory barriers applicable to this development stem from the same issues discussed in scenarios 1 and 2 where there sale and distribution of electricity is regulated. Similar solutions to those previously discussed would also be applicable to this scenario depending on the ownership model.

The scenario scores are listed in the table below.

Table 9: Scenario 3 – Summary Scoring

Criteria	Score
Use of community space	10
Fulfill an energy need	8
Regulatory barriers	4

4.3 Further Analysis

Arup are working with Caltrans to understand the opportunity for integrated highway generation and a future revision of this report will provide a case study demonstrating this.

CHAPTER 5:
Community Generation Scenario 4 – Community Wind

Community Wind in a San Francisco Park

Figure 13: Example of Community Wind Energy

Photo source: Arup

5.1 Summary

Within this scenario a community wind turbine is placed in a San Francisco Park to generate renewable electricity.

The positive use of community space was limited in this scenario due to the visual impact of the turbine. Fulfilling an energy need was also limited due to the inadequate potential to provide a meaningful amount of energy to San Francisco residents. Regulatory and technical barriers were seen as a large barrier to the adoption of this scenario and significant challenges such as aviation and visual impact would have to be addressed to develop a large scale wind turbine in San Francisco.

5.2 Workshop Discussion and Insights

5.2.1 Location and Scale

It would not be feasible to supply all of the energy needs of Central SoMa with community installed wind power. A typical large scale commercial wind turbine has maximum generation output of 2.5MW[22]. An area of the size of Central SoMa is likely to have a peak energy demand of around 90MW[23]. Within urban areas such as San Francisco there is not the available land space to match wind power with demand.

Urban wind energy would serve as a 'beacon' of San Francisco as a 22nd century city and educational tool, rather than a functional/large scale electricity production source. Wind turbines in Michigan, Delaware have become a tourist attraction with locals providing maps and tours of where best to see the areas many commercial wind farms. A prominent wind energy development in San Francisco has the opportunity to highlight the city's positive climate ambitions to an international audience.

5.2.2 Ownership

There are many available ownership models for wind energy plants. Four models are provided below:

1. Local electric utility
2. Local municipal electricity utility
3. Third party
4. Community

[22] A typical capacity factor for a commercial, well placed wind turbine is in the range of 30-40%. Meaning on average a 2.5MW turbine will deliver 0.875MW.

[23] Figure calculated from the Arup Report: CEC-500-2014-FEB by summing the distribution feeder's peak load in the Central SoMa area.

An electric utility can own and operate generation in California and wind energy would be applicable to the local utility RPS[24] goals. A local utility can not specify the location of the generation source and would issue a request to the market and receive proposals back in response to a stated energy generation capacity. The utility would be obligated to select the proposal (if any) that delivers best value to the rate payers.

In San Francisco there is a local municipal electricity utility called San Francisco Public Utilities Commission (SFPUC). SFPUC install, own and operate over 7MW of solar capacity in the city and could develop wind generation in the same model. There are no regulatory barriers to this ownership model.

A third party developer can act in the way of a traditional wind farm developer and site renewable generation within the city limits. Within the bounds of the current regulatory framework the developer would sell the power to the local utility under a feed-in-tariff or similar arrangements.

As is common through the world, the local community can invest in the wind energy project with capital. The project developer could seek crowd source funding from local residents to own a stake in the wind turbine and receive revenue from the sale of the electricity. The electricity would not be connected to their individual houses but participants would receive an income from every kWhr sold to the grid. A typical 2.5MW single wind turbine has an installed cost of around $4.5m.

There are other opportunities for large scale wind that could provide San Francisco with more wind energy capacity than is possible within the city limits, The SFPUC owns and operates a HV transmission corridor that runs from the Hetch Hetchy Hydropower stations near Yosemite to the PG&E Union City Substation in the City of San Francisco. It may be feasible to install wind turbines on City owned land in the areas around Hetch Hetchy and transport this power back to the city for consumption. This however is not a CIRE project and is not the focus of this report.

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[24] California law requires state utilities to procure 33% of their electricity needs from eligible renewable resources by 2020. This policy is called the Renewables Portfolio Standard (RPS). Established in 2002 under Senate Bill (SB) 1078, accelerated in 2006 under SB 107 and expanded in 2011 under SB 2.

5.2.3 Risks and Barriers

Many of the identified risks and barriers are common to all wind energy development. Barriers such as environmental and technical issues would prevail at certain sites in the city as would local objections groups. A well management development process consisting of screening, feasibility and environmental impact reporting is recommended to determine the most suitable site for development.

Table 10: Scenario 4 – Community Wind

Criteria	Score
Use of community space	5-6
Fulfill an energy need	2-3
Regulatory barriers	2-7

CHAPTER 6:
Enabling Technology Scenario 5 – Commercial Microgrid

Individual commercial property owner who values self-generation and energy resilience. Property owner has the opportunity to continue to power their own development in the event of a grid outage

Figure 14: Single Owner Microgrid Schematic

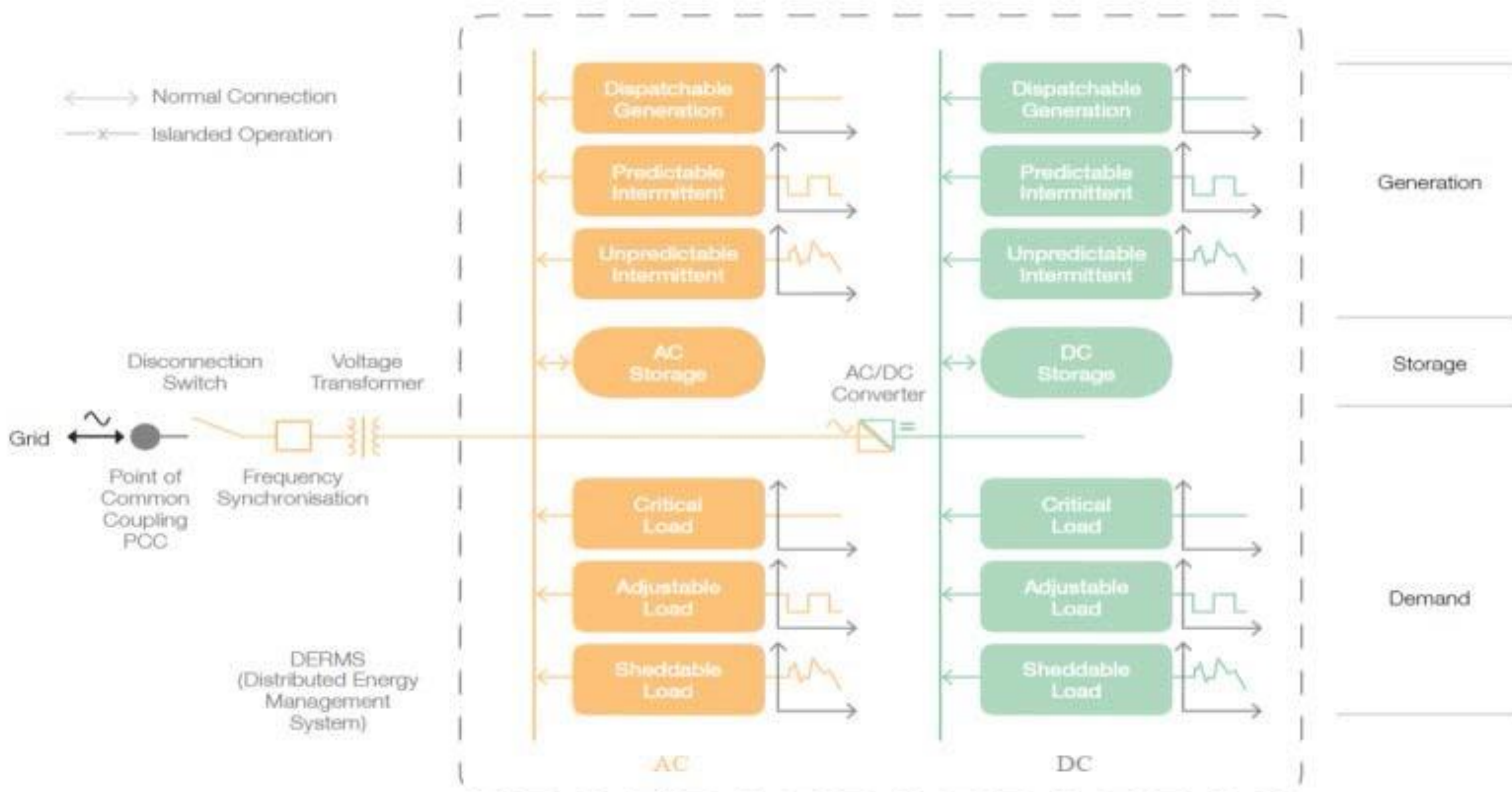


Photo source: Arup.

6.1 Summary

Within this scenario a single commercial property owner values energy resilience. The property owner has a desire to be able to keep their property powered with renewable electricity should the wider grid be lost.

The term 'Microgrid' describes this mode of operation.

The use of community space scored high due to the fact that the technology to integrate generation assets to island from the grid does not require a significant space take. It was assumed that all of the generation assets are existing and that a control system or systems would integrate the assets to allow islanded operation.

Commercial property owners depend on electricity to maintain their business continuity and this scenario fulfilled an energy need. Commercial properties are often provided with diesel generators for island operation, but there is a strong desire from property owners to operate independently of the grid with more sustainable sources such as fuel cells and PV combined with energy storage.

Regulatory barriers are a large barrier to the adoption of this scenario if the owner of the building was not on a single electricity meter / land parcel. Should the owner be on a single land parcel with one energy meter then the regulatory barriers were removed.

6.2 Workshop Discussion and Insights

Commercial property owners and developers expressed a market need to be able to operate during a grid outage. For commercial buildings, the ability to achieve this for life safety and often priority loads is in the form of standby diesel generators or other measures such as Uninterruptable Power Supplies (UPS). Data centers are a form of commercial building that values continuous operation and Central SoMa may be a prime location for such buildings due to the future zoning of the area. Californian Electrical Codes mandate certain loads be provided by standby power. This mandate does not extend to non-life-safety loads required for business continuity. Standby generators have limitations for extended outages such as those seen during East Coast events such as Sandy. A typical commercial building will be supplied with enough fuel for a 24 hour or less outage when standby generators are utilized. Should batteries are used for life safety loads such as exit lighting power will only be typically provided for 90 minutes.

In order to determine the quantity of electrical outages during 2013 in California, Eaton's 2013 Blackout Tracker Annual report has been used to construct Table 10.

Table 11: 2013 Electricity Outages in California

Total number of people affected by outages	1,948,736 (5 % of population)
Total duration of outages	22 days
Total number of outages	464
Average number of people affected per outage	5,428
Average duration of outage	5 hours

Source: Eaton Blackout Tracker 2013

An ideal system would have a mix of generation sources such as PV, gas generation (bio-gas fuel cells) and energy storage to provide an owner with a mix of generation assets to be able to operate in island mode as a microgrid.

These technologies are all available in the current market and microgrid controllers to manage such systems have been developed. There has not been mass adoption to date of such strategies and this is primarily due to cost versus perceived risk. In California there are indeed power outages. However, the average power outage in California is five hours. The existing arrangement that is common in buildings of UPS and diesel generators faces no issues in dealing with such outages and it is the owner's choice to install such technologies. Some innovative forward thinking agencies are moving to a microgrid arrangement such as Santa Rita Jail and the University of California, San Diego. Here all loads are able to be run and operated during extended outages and each of these examples has a large renewable component of generation.

A single owner building or campus can implement a microgrid with no major regulatory hurdles[25]. The technology, while new and often custom designed is being developed and more and more vendors are starting to supply microgrid systems. Should the owner of a distributed campus wish to operate as a microgrid and the owner has multiple meters / land parcels then this is much more difficult. The ability for campus owners to share generation across buildings is described in scenarios 1 and 2. There are solutions that will allow generation to be shared via virtual metering. None of these solutions will allow the campus owner to share this generation

[25] Interconnections will require more work than typical as the generation will operate in island mode. Detailed protection meetings with the utility will be required to ensure that suitable protection is installed to allow the generator to operate when in island mode.

in the event of a utility outage and operate as a campus microgrid. Only the building to which the generation is connected will be physically connected to the generation asset. All of the other buildings will lose this power source.

The main barrier to mass deployment of microgirds is the upfront capital costs. A microgrid is much more than just an emergency power supply and requires specialized planning and design. It has to operate as a self-contained grid, managing the delicate balance of supply and demand while providing the necessary electrical safety functions. Microgrids also require significant investment in generation and storage (enough to power the asset), with the generation operating continuously so it can transition seamlessly to 'island mode' when the wider grid goes down.

The scoring for this scenario is shown in Table 11.

Table 12: Scenario 5 – Summary Scoring

Criteria	Score
Use of community space	10
Fulfill an energy need	9
Regulatory barriers	3-8

CHAPTER 7: Enabling Technology Scenario 6 – Residential Microgrid

A residential community that values self-generation and energy resilience. Community has the opportunity to continue to have power in the event of a grid outage.

Figure 15: Typical Central SoMa Community

Photo source: Arup

7.1 Summary

Within this scenario a distributed residential community values energy resilience. The residential community has a desire to be able to keep their property powered with electricity should the wider grid be lost.

The term 'Microgrid' describes this mode of operation.

The use of community space scored high as the technology needed for island operation was not expected to have a large space take. It was assumed that generation in order to allow island operation was already in place.

The fact that sustained operation in the event of a grid outage fulfilled an energy need was dependent on the installed cost. If the cost of a secure energy supply was not a few percentage points above a standard electricity supply then the energy need was significant for the security the service provides. A significant cost increase over a standard electricity supply reduced the energy need of such a service.

Regulatory barriers were seen as a large barrier to the adoption of this scenario if the community was not on a single electricity meter / land parcel.

7.2Workshop Discussion and Insights

7.2.1 Market Need

For commercial community members (as discussed in the previous scenario) a market need was identified and clear. However, this did not transpose to the residential market described in this scenario. The need of the system would be very much influenced by cost. If the microgrid was at little cost and did not require any community member involvement, then the energy need score increased.

The very scenario presented in this section is being implemented in Connecticut which was hit hard during Superstorm Sandy. In Connecticut[26] (amongst other eastern states) community microgrids are being developed. In California, it has been a long time since a large number of people have experienced long term loss of power. It was shown in the last scenario that 5% of the California population will experience a power outage annually and the average period for this outage is 5 hours. There is a very strong correlation between when a consumer last experienced a long term power loss that affected them and the perceived marked need for such a system. This is clearly demonstrated by the work ongoing in the east coast following their extended power outages.

[26] The state developed the Microgrid Grant and Loan Pilot Program under Public Act 12-148, Section 7. The Act requires that Department of Energy and Environmental Protection establish a microgrid grant and loan pilot program to support local distributed energy generation for critical facilities.

7.2.2 Ownership Models

To develop a community microgrid requires detailed technical design. Individual community members are not best placed to do this. A microgrid raises complex questions that require resolution, such as:

- How and when does the system island from the utility grid?
- What safety measures are deployed?
- How does the system reconnect to the wider grid?

The ownership models that are suitable for community microgrids would be:

- utility ownership
- third-party ownership

In response to a market need or a community request, a utility may want to own and operate a microgrid for the community. The utility determines the boundaries of when the system islands from the grid and actively controls the microgrid to maximize the electrical reliability of the microgrid. The business model for the microgrid is twofold. First customers of the microgrid have all of their energy needs over the course of a defined period provided by the on-site (or local to the utility substation) renewable resources, and the utility charges a premium to these customers for having 100% renewable energy. The second value stream is a reliability increase. Customers pay a premium for having uninterruptable power (subject to generation output and storage levels). Such a scenario is not feasible in the current regulatory regime but in the changing regulatory landscape in California a future can be seen where this is permitted. A utility is generally not able to give certain rate payers preferential services.

Third-party ownership of the microgrid will include all items required to functionally operate as a microgrid, including the generation, storage, and controls equipment. There are US precedents of third-party community microgrid development work ongoing in the state of Connecticut, spurred by the devastation caused by Superstorm Sandy in 2012. A barrier to the early adopters can often be the large up-front capital cost. One a potential business model is for a microgrid developer to set up a microgrid with the security of a long-term PPA, similar to how a community solar scheme can operate, and eliminating the up-front capital costs to the end user. The developer may be the community developer or a separate third-party microgrid developer. The third-party developer still needs to follow the same processes and utilize the utilities distribution assets (and pay a rental for) to minimize regulatory hurdles and reduce a duplicated electrical distribution network. As the utility example, this model is not feasible under the current regulatory regime in California as a third party cannot sell electricity in the utilities territory.

The scoring for this scenario is shown in Table 12.

Table 13: Scenario 6 – Summary Scoring

Criteria	Score
Use of community space	7
Fulfill an energy need	4-6
Regulatory barriers	3

CHAPTER 8:
Enabling Technology Scenario 7– Community Microgrid

A community-wide 72-hour power outage – what critical community infrastructure is important? How could these items be powered?

Figure 16: Illustration of Community Infrastructure

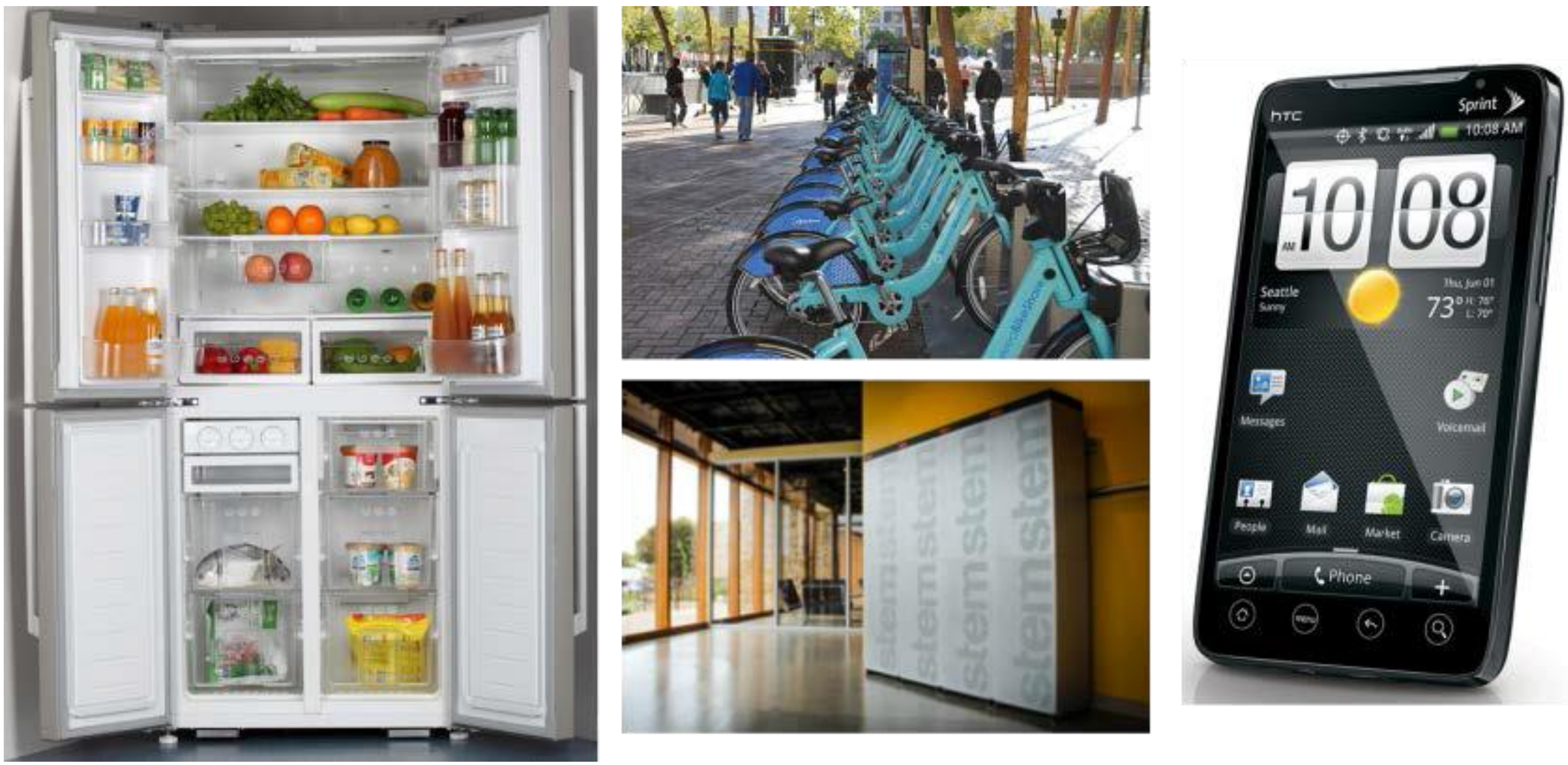


Photo sources: GE; CCSF, Stem and HTC

8.1 Summary

A community wide 72 hour power outage was discussed in this scenario. What critical community infrastructure is important and how could these items be powered was the focus of this scenario.

This scenario considers the use of existing community generation sources to power the community's essential loads in the event of a power outage. No new generation is proposed. A microgrid control system is required to manage the balance of electricity supply and demand.

The use of community space scored high as the technology needed for island operation was not expected to have a large space take. It was assumed that generation in order to allow island operation was already in place.

This scenario fulfilled an energy need and there was a significant value identified to allow island operation. The value was increased by utilizing existing community infrastructure and deploying the generation to create local microgrids.

Significant cost and technical barriers due to existing grid/system design, grid integration, and integration of technologies were identified within this scenario as the focus was on existing electrical infrastructure and the modernization required to operate as a microgrid.

8.2 Workshop Discussion and Insights

8.2.1 Essential Loads

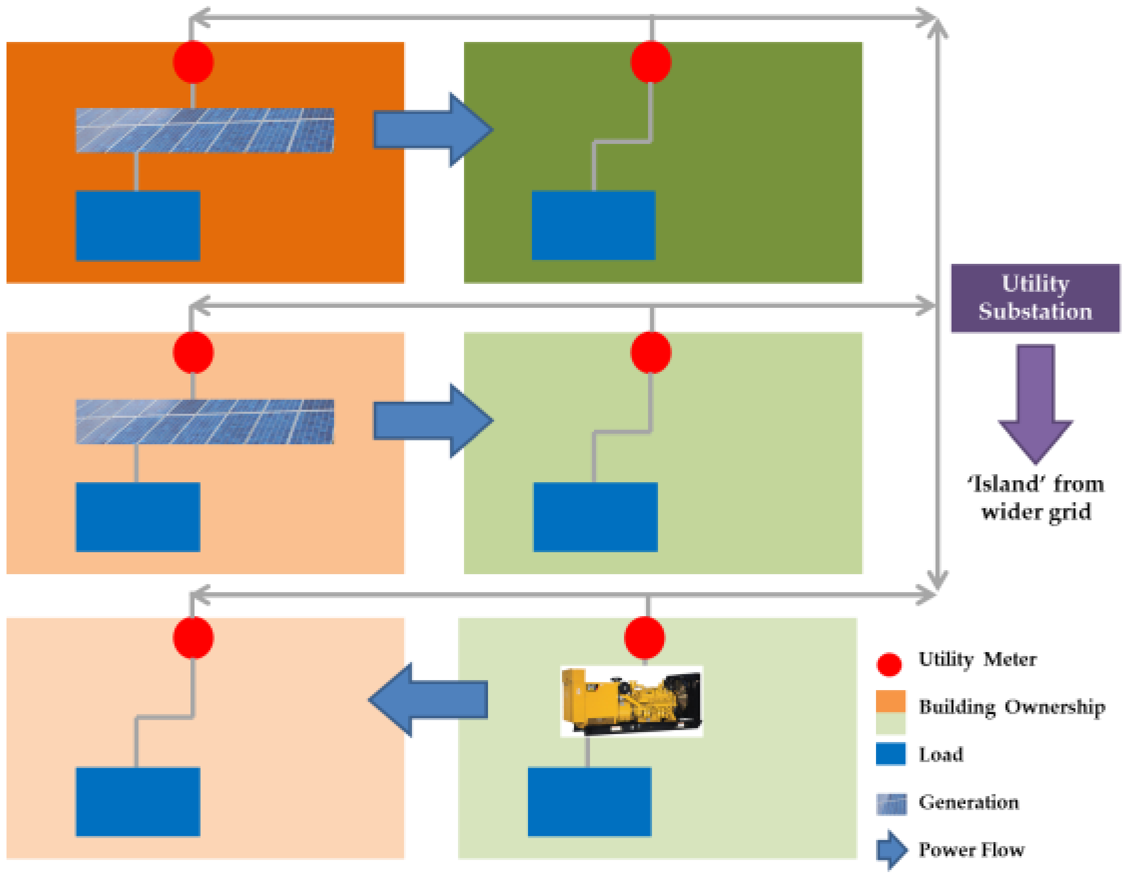
Basic lighting and refrigeration are essential loads that require power in the event of an outage as is the use of a receptacle to power communication devices such as cell phones. Televisions, while they are useful for obtaining news, are not essential as these services can be received from lower power devices such as cell phones and radios. In an outage, the average home will have significantly reduced energy consumption, should only essential loads be operated.

8.2.2 Power Supply Options

Communities could be powered by utilizing existing and new assets (where needed). Existing assets could be dispatched by aggregators or the utility to provided limited power to circuits. An individual property would have to operate on a reduced load in order to maximize the community members who could participate in this scenario. Adding the controls to load manage in every home is likely to be cost prohibitive. The premise is that the community acts as a community and takes responsibility for reducing their load, only turning on essential services. Each community would be assigned a maximum 'outage' load and only be able to turn on these loads. This number will be based on the number of properties on the circuit and the emergency generation capacity. Owners of generation would receive an income for operating their generation in an emergency and the utility or third party would receive compensation for orchestrating the network of generators to supply the emergency loads.

Central SoMa already has a diverse set of existing generation and storage assets (e.g. fuel cells, diesel back-up generators, Solar PV arrays, UPS's etc.). It is recommended that an inventory of these assets is made to allow the generation potential and outage demand to be compared.

Figure 17: Community Generation Sharing



The inventory should consider the following:

- Ownership and willingness to allow shared operation in grid emergency e.g. is there any spare generation capacity
- Which are resilient / will survive a disaster and grid outage? Which won't? (e.g. non seismic designs, those that don't have good fuel supply)
- The circuits that the generators are connected to

8.2.3 Critical Circuit Analysis

Once the capacity of the generation on a circuit / substation is known and the available spare in an emergency, the maximum outage loads to be operated can be calculated.

An evaluation will determine which parts of the grid could be disconnected as microgrids (e.g. comparing normal loads versus emergency loads on those circuits). The utility substation would be required to separate from the wider grid to prevent back feeding on a network which is no longer powered and may have field staff working during the power restoration process.

Connecticut is evaluating critical loads for both public and private buildings (hospitals, emergency first responders, data centers, switchboards)and Connecticut regulators are sponsoring community microgrids to share generation when the grid goes down and learning could be taken from these projects and implemented in California.

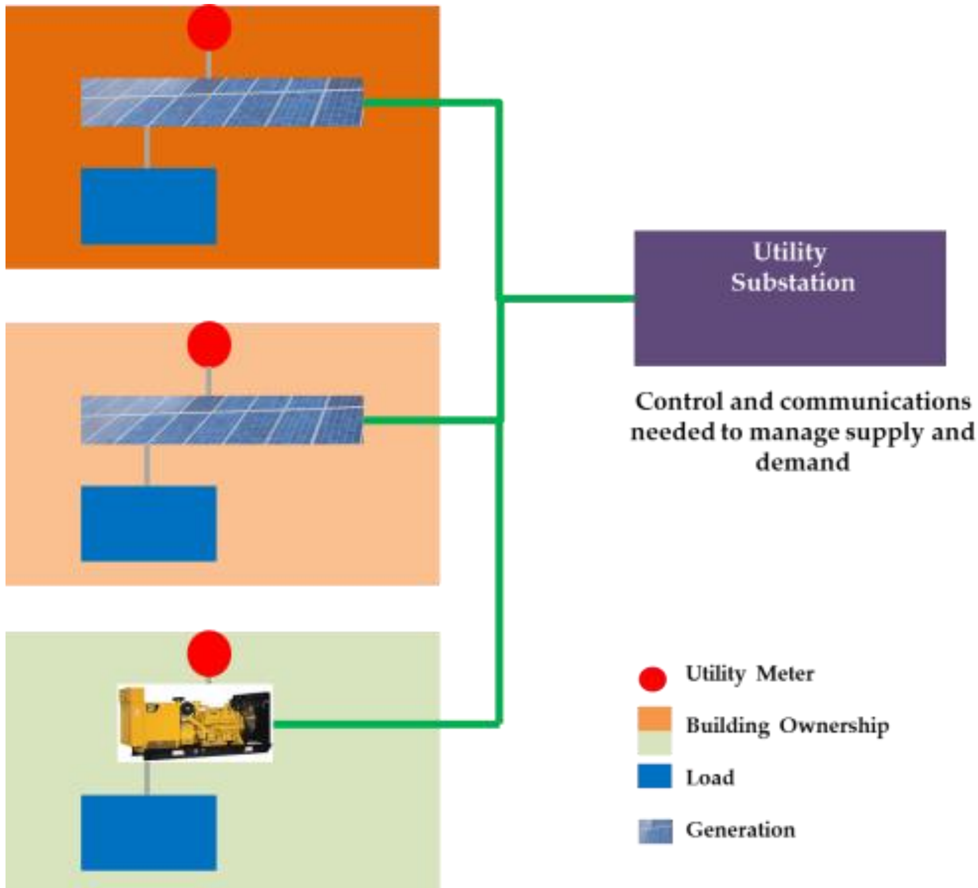
8.2.4 Technology Implementation

Safety of the utilities line-men[27] is a key requirement of the operation of this system. When generation is live and back feeding into the utility system there is a risk to workers. Interconnection and anti-islanding standards have been developed to manage this risk and ensure safety.

Controls would be required at every generator that reports back to the utilities control and monitoring system so the utility can evaluate the status of the powered systems. The utilities will need to manage where the power flow is to ensure safety. The utility or third party would have to effectively manage a community microgrid.

[27] A line man works on the electrical distribution system and restores power in the event of an outage.

Figure 18: Controls and Communications



Existing anti-island features of renewable energy generation would need to be relaxed in these emergency modes. Advanced inverters[28] would be required that can load follow and provide voltage and frequency regulation services to manage an islanded grid area.

In an island mode, the island generation sources and control system will be responsible for the voltage and frequency of the islanded area. A microgrid controller will be responsible for controlling the generation sources, defining the grid leader to which other generation sources synchronize and maintaining power quality to a reasonable level to allow all of the devices within the microgrid to operate. One of the most important steps in creating any microgrid is to create an effective model. Modeling all possible configurations and transitions of the network will identify how the systems behave in all modes of operation and will allow safe systems to be designed.

The scoring for this scenario is shown in Table 13.

Table 14: Scenario 7 – Summary Scoring

Criteria	Score
Use of community space	10
Fulfill an energy need	10
Regulatory barriers	1

[28] In California there is a Smart Inverter Working Group. Smart Inverters are expected to be mandatory in California from October 2015.

CHAPTER 9:
Enabling Technology Scenario 8 – Resilient Transit Network

Transit network has the opportunity to continue to operate in the event of a grid outage

Figure 19: San Francisco Transit Networks

Photo source: BART and SFMTA

8.1 Summary

The impact of a community wide power outage on the continuity of transit network operation was discussed in this scenario.

The use of community space scored high as the technology needed for island operation was not expected to have a large space take.

The fact that sustained operation in the event of a grid outage fulfilled an energy need was important as workshop attendees did perceive a significant value to island operation by allowing trains to move in the city. There was a power outage to the Mission substation in 1998 and the San Francisco Municipal Transportation Agency (SFMTA) electric buses could not run, blocking many San Francisco streets.

The technology is available in the current market place for the project proposed here. Regulatory barriers around the distribution of electricity would be required to be investigated to determine if this scenario is feasible.

8.3 Workshop Discussion and Insights

A case study was analyzed that discussed methods of powering the BART network in the event of a grid outage. Similar analysis work could be carried out for the SFMTA and other Californian transit agencies.

8.3.1 Baseline Conditions - BART

The BART San Francisco system requires between 3MW and 7MW of power to operate, depending on the train schedule. In a power outage, running fewer and slower trains would significantly reduce the required power to operate the trains.

BART obtains its power via a long term contract with Bonneville Power Administration[29]. BART's electricity is distributed to its assets in San Francisco via substations at Embarcadero and Valencia St (supplies power to Powell). The distribution voltage is 34.5kV and is stepped down to 1kV for use in moving the train's via traction power. In contrast, BART's stations are supplied from local electricity services and are separate from the traction power electrical system. Both electrical services would require continuity in order to allow the BART system to continue to operate.

[29] The Bonneville Power Administration (BPA) is an American federal agency based in the Pacific Northwest. BPA was created by an act of Congress in 1937 to market electric power from the Bonneville Dam located on the Columbia River and to construct facilities necessary to transmit that power. Congress has since designated Bonneville to be the marketing agent for power from all of the federally owned hydroelectric projects in the Pacific Northwest. Power is purchased from BPA and distributed by PG&E to the BART San Francisco system.

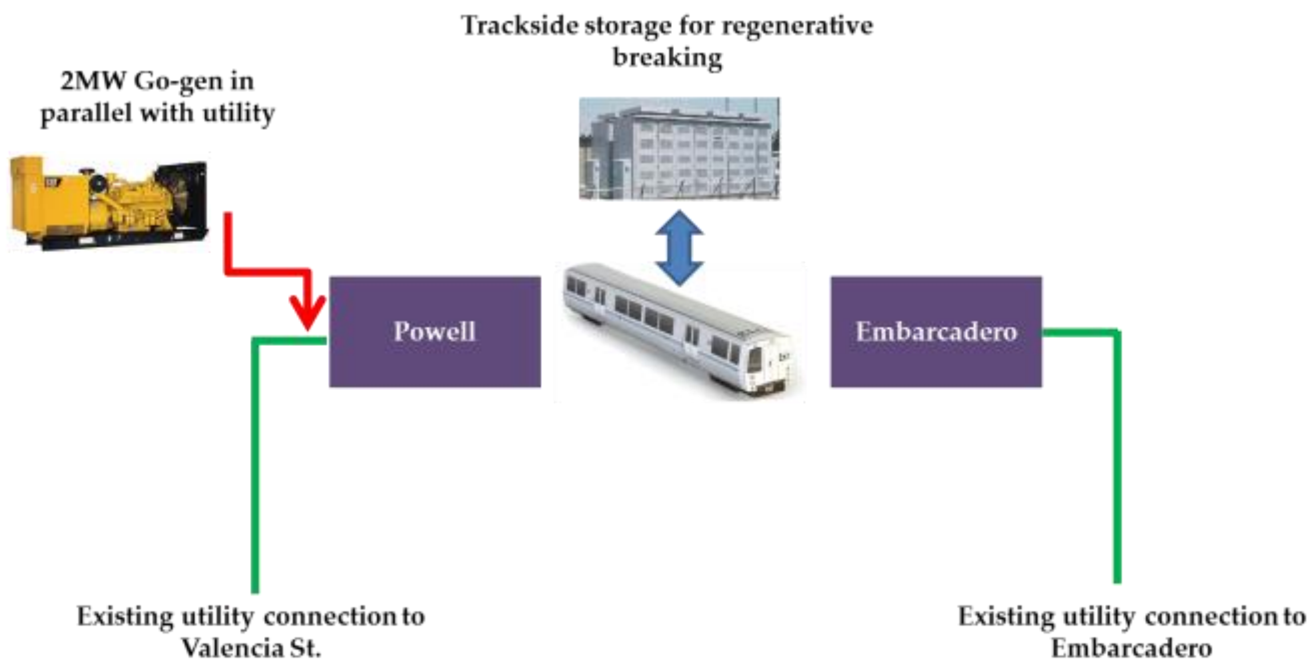
8.3.2 How Could Assets Be Powered

The NRG Energy Center San Francisco can be used to provide power to BART in an emergency and keep the trains running, albeit at a reduced capacity. The NRG Energy Center San Francisco is a wholly owned subsidiary of NRG Thermal, an NRG Energy Inc. company.

NRG are investigating the feasibility of installing a 2MW cogeneration plant at their existing district heating system in San Francisco. The installation of this device will increase the efficiency of their existing plant (see Task 3b report for details on the NRG plant). The 2MW cogeneration plant, connected to the Valencia Street substation circuits, can be used to provide BART with sufficient power during an outage[30]. Again as in the previous scenario, controls and operational procedures would need to be put in place to ensure safety standards are maintained. A cross link to back up station power from this same source would ensure that both stations and trains stay operational.

In addition to the NRG co-generation plant, BART could install trackside energy storage for improved regenerative breaking capture and have additional power available in an outage.

Figure 20: BART Downtown San Francisco Traction Power Supply



Due to BART's variable energy profile, BART is an ideal candidate for a PV integrated with storage solution. This would further assist the network in becoming resilient in the event of a power outage. BART currently has PV assets in operation. Adding additional capacity, storage, and additional controls to allow island mode operation is recommended for further study.

[30] Interconnection and island mode operation studies would be required with PG&E.

8.3.3 Barriers

There are regulatory barriers to the sale of electricity as described in the community energy scenarios. In addition, this scenario may face further non-regulatory barriers such as economics. BART has long term energy contracts for power that may be less expensive than local power supplied from a cogeneration plant. A study of the improved resilience value for critical transit infrastructure compared to any premium cost of energy would be valuable.

The scoring for this scenario is shown in Table 14.

Table 15: Scenario 8 – Summary Score

Criteria	Score
Use of community space	7
Fulfill an energy need	8
Regulatory barriers	5

CHAPTER 10: Conclusion

The 24-square-block area that makes up Central SoMa is poised for significant growth adding nearly 12,000 residential units and 9 million square feet of commercial space. This new growth may increase the existing electricity demand by over 40MW.

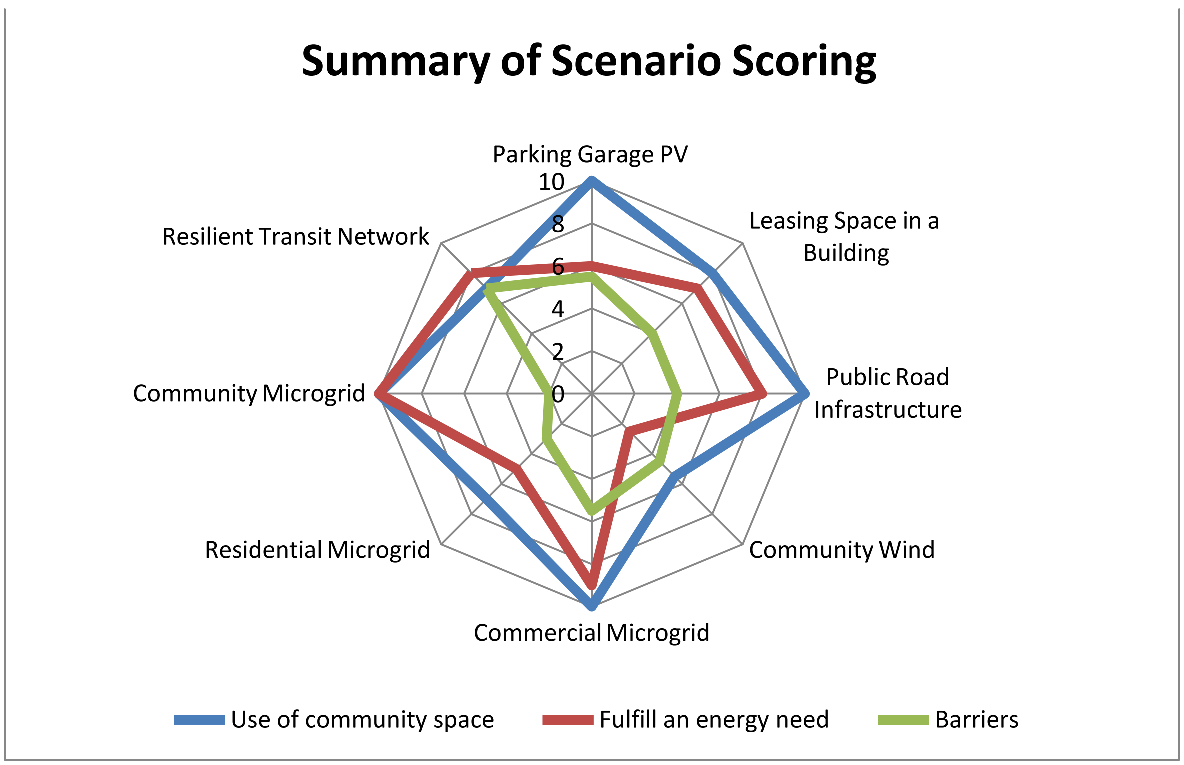
The area is not currently an area that has seen a significant penetration of renewable energy. The existing baseline of installed renewable energy totals just 2.6MW.

There is the opportunity to change this and significantly increase the amount of renewable energy installed in the district and other similar urban districts throughout California. Sample implementation scenarios are presented within this report.

Parking lot PV in Central SoMa at peak generation has the potential to offset 20% of the new energy demand. Adding other technologies such as fuel cells and commercial building PV can increase this percentage even more. It is recommended that a renewable energy goal for Central SoMa be implemented and state that new development within Central SoMa be energy neutral.

All of the results from the eight scenarios have been plotted onto a radar diagram.[31]

Figure 21: Summary of Scenario Scoring



[31] Where ranges were presented in the report an average has been used per scenario.

The radar diagram allows some interesting conclusions to be drawn.

The results show a clear order between the opportunities, needs and barriers. Opportunity and need sits at the outer edges of the radar chart, demonstrating a clear desire for CIRE projects.

It is clearly demonstrated that regulatory barriers present the biggest challenge to deploying the identified CIRE projects and therefore the resolution of these barriers should be focused on in future work.

10.1 Community Energy

Scenarios at the outer ring of the radar diagram demonstrate the optimum location for energy and/or storage assets in local communities. High value sites include integrating these assets into parking garages and public road infrastructure (onto, beside, or underneath). The further analysis carried out within this report has provided case studies to further assess the barriers.

In a parking garage scenario it is recommended that EV charging is integrated with PV to provide the opportunity to charge EVs directly from clean, renewable energy. Central SoMa has the potential to increase PV installations nearly six-fold by this novel approach that has been demonstrated at the San Diego Zoo. Garage owners can generate revenue from the sale of premium parking spaces, not electricity and therefore comply with current regulations.

Integrating renewable energy into road infrastructure is being actively studied by Caltrans and Task 6 provides details of their work to date. There are some challenges in terms of cost and the additional safety measures that PV adjacent to the road entail, however, the opportunity for such integrated dual use infrastructure is there. At the time of writing (2014) none of the Caltrans sites that were studied have progressed to construction. Economics have been the reason for this and this has been driven by the shape of the parcels and the proximity to electrical off-takers. Experience from Oregon tells us highway integrated renewables is feasible when the right site is selected. Oregon has developed two road side PV installations in the state. Their first scheme, the Oregon Solar Highway completed in 2008 at a cost of $1.3m resulted in the installation of a 104kW array (cost of $12.50/W of installed capacity). This project was completed adjacent to the highway and at a small scale. The second project, the Baldock Solar Station completed in January 2012 in a rest area at a cost of $10m resulted in the installation of a 1.75MW (1750kW) array (cost of $5.70/W of installed capacity). Some of the cost reduction is from the falling module cost over the four year period, however a great deal of cost reduction was from scale, site selection and experience. The Oregon experience has shown that suitable site selection and scale can greatly assist in reducing the installed cost of PV on public road infrastructure. A noteworthy point is that the Oregon examples are large parcels that are less complex to develop than interchanges.

Common barriers to CIRE implementation have been ownership models and energy distribution and sale in the current regulatory regime. Every community energy scenario addressed in the workshop identified regulatory challenges in the sale and distribution of energy.

There are significant barriers to transmitting energy in the public rights of way and selling energy to more than two adjacent properties. There is a strong desire to maximize renewable energy on properties but often this would involve sharing electricity to neighboring buildings. If these are not within a common ownership or there are more than two buildings on a single land parcel this is not permissible. We recommend that studies are performed with the IOUs and regulators to agree how best to solve this issue. The SDG&E sustainable community's trial may be a successful implementation path for this with amendments to allow the building owners to receive the renewable energy. Other methods may be allow to renewable energy sharing between buildings, either with the utility acting as an orchestrator or a third party performing this role. In such cases, the utility services of guaranteeing power delivery (an insurance service), storing (a battery service), distributing (a delivery service), and maintaining (a maintenance) service will need to be appropriately valued.

If a common building owner want to generate at one building and supply other local buildings that are supplied with separate electricity meters, there are new ways in which to share generation and awareness about this programs have proved to be limited. VNM and aggregated NEM are two of the vehicles that will allow generation to be shared in multi-tenant or a distributed campus setting. It is also recommended that rates such as the Campus Rate in ConEdison's territory are considered by regulators and IUOs in California to allow generation sharing of up to 20MW.

10.2 Enabling Technologies

Except in the purely residential scenario, a strong market need has been identified for commercial, community and transit microgrids. In times of grid stress it is envisaged that large areas of the existing electrical grid can separate and power themselves with energy generation and storage. The key challenges to such a system are both technical and regulatory.

Commercial systems on contiguous land parcels supplied by private wires are not a regulatory challenge. Vendors are making controllers to operate such systems, albeit in a custom manner. The Department of Energy is currently offering funding for the design of non-custom microgrid controllers in the scale of 1-10MW with a view to speeding their commercial deployment which will greatly assist in the deployment of such systems.

When planning at the community scale, how to safely power an area of the grid while the wider power is unavailable is much more difficult. Here an orchestrator is needed to manage all of the interfaces of supply, demand and safety. This function requires significant technical knowledge and is a job suited to an existing IOU or third party energy provider. The orchestrator would need close links to workers on the ground restoring power to ensure when a worker thinks a distribution circuit is not powered, that it is indeed the case. The technology to control such a microgrid would likely be based on a centralized control or distributed system with reporting back to a common interface, that an IOU can access to cross-check generation status with field observation. It is recommended that further research work be carried out in community microgrids, both existing and new build, to determine the operating practices that would need to be set in place to allow the safe operation of the system.

GLOSSARY

Term	Definition
AB	Assembly Bill
BART	Bay Area Rapid Transit
behind-the-meter generation	Generation installed on an individual customer's electricity distribution system, behind the utility meter.
Caltrans	California Department of Transportation
CCSF	City and County of San Francisco
CIRE	Community Integrated Renewable Energy
CPUC	California Public Utilities Commission
DC	Direct Current
eco-district	an urban planning tool that integrates objectives of sustainable development and reduces the ecological footprint of an area
EPA	US Environmental Protection Agency
EV	Electric Vehicle
FHWA	Federal HighWays Administration
IOU	Investor-owned Utility
Island	Operate independently from the utility grid
kV	kilovolt
kW	kilowatt
LEED	Leadership in Energy & Environmental Design
local renewable power	Generation installed on the distribution network so that benefits are gained locally
microgrid	Microgrids are small-scale versions of the centralized electricity system. They include local generation and or energy storage. They achieve specific local goals, such as reliability, carbon emission reduction, energy arbitrage, diversification of energy sources. They have the ability to island

	from the wider grid and operate independently.
MW	megawatt
NEM	net energy metering
PG&E	Pacific Gas and Electric
ROW	Right of Way
RPS	Renewables Portfolio Standard
SFMTA	San Francisco Municipal Transportation Agency
SB	Senate Bill
SMUD	Sacramento Municipal Utility District
SoMA	South of Market
Sq.ft	Square Feet
smart grid	A smart grid is a modernized electrical grid that uses information and communications technology to gather and act on information, such as information about the behaviors of suppliers and consumers, in an automated fashion to improve the efficiency, reliability, economics, and sustainability of the production and distribution of electricity (USA, 2013)
UPS	Uninterruptable Power Supplies
VNM	Virtual Net Metering

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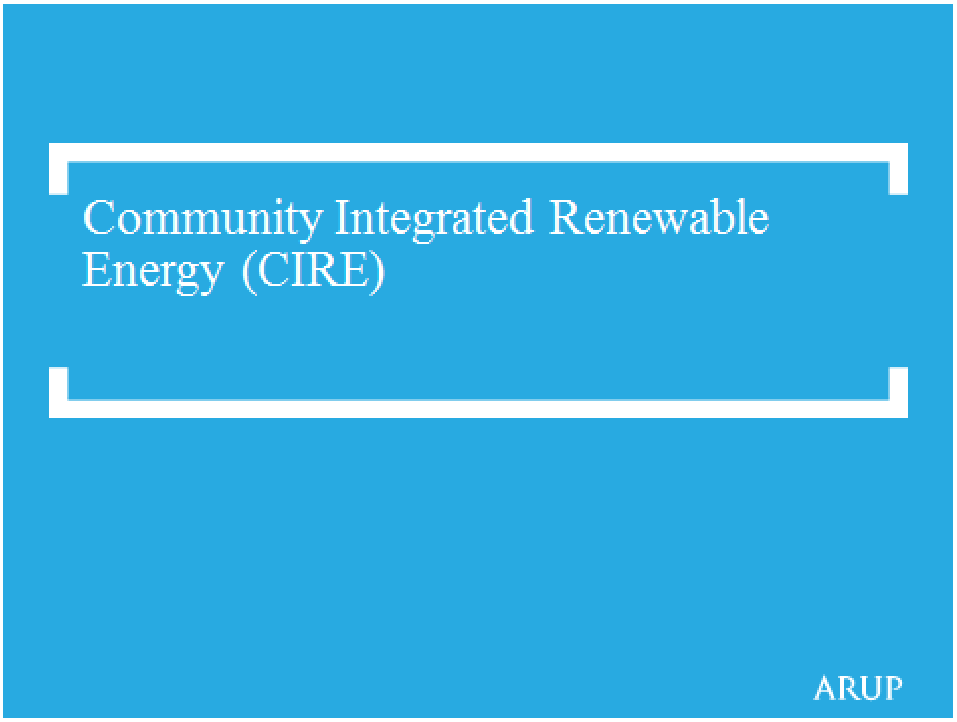
Workshop Presentation and Invite

A.2 Workshop Presentation



Agenda

Time	Activity	Duration (m)
11.30 – 12.15	Gathering & Introductions over Lunch • Introductions • Goal Statement • Project Overview • Central SoMa overview	 15 5 10 10
12.15 – 12.20	Context and Overview to the Scenarios	5
Tables 1 and 2 12.20 – 1.10 **Tables 3 and 4** 1.15 – 2.05	Community Shared Energy Discussion • Individual Group Discussion • Reporting Back	 35 15
Tables 3 and 4 12.20 – 1.10 **Tables 1 and 2** 1.15 – 2.05	Enabling Technologies • Individual Group Discussion • Reporting Back	 35 15
2.05– 2.30	Next Steps Close and Thanks	15 10

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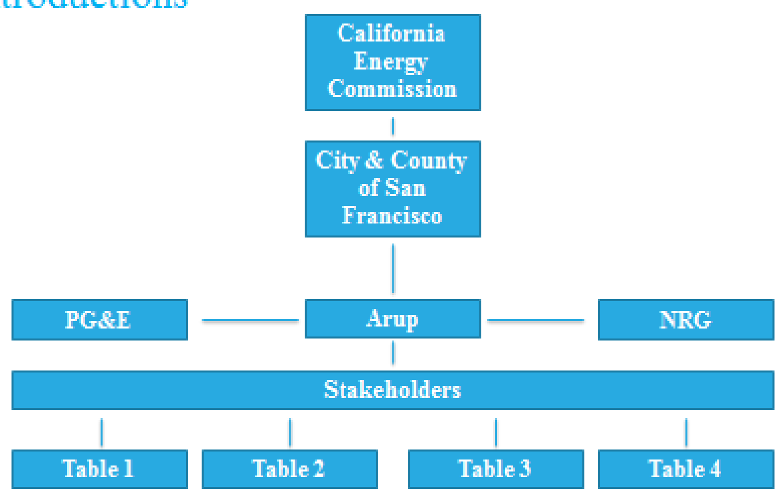
Introductions



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Goal Statements

- Identify suitable community integrated renewable projects that best serve the needs of Central SoMa
- Identify suitable enabling technologies that can allow generation to be shared within the community
- Identify technologies that allow energy resilience and the value that this brings

Project Overview

- CEC grant to investigate Community Integrated Renewable Energy (CIRE)
- CIRE projects allow a community to have energy needs to be supplied from local renewable sources
- Support state goals of increasing California's local renewable generation to 12,000 MW by 2020, and San Francisco's goal of 100% renewable electricity.

Project Overview

- CIRE Model is new, integrated approach for existing communities
- Identify Barriers
- Pools Resources
- Multi-Stakeholder

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Project Overview

- 4 Main Project Tasks:
  - Regulatory barriers and cost implications
  - Identify CIRE projects
  - Improve existing district energy center
  - District energy assessment

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Central SoMa Overview

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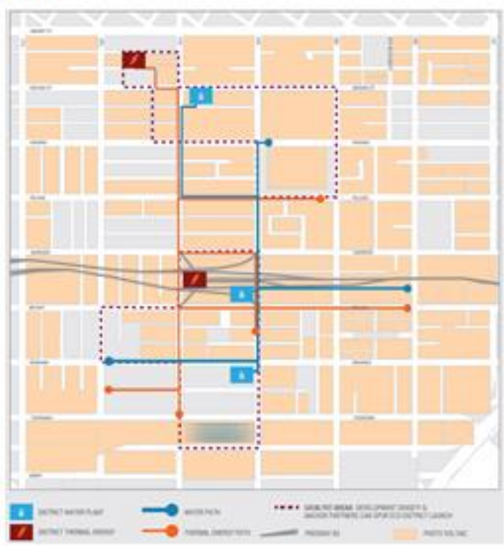
Central SoMa Overview

The Central SoMa is a dense, transit-rich area that extends from 2nd Street to 6th Street and Market St to Townsend St

The area is undergoing a period of change:

- Significant rezoning
- Identified eco-district area
- New subway
- 10,000 new housing units
- 35,000 new jobs



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Central SoMa Overview

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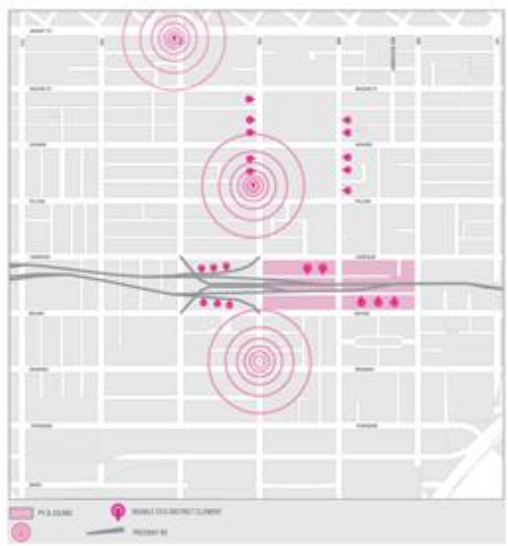

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Group Discussions

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Group Discussions

- Each table will assess one CIRE project
- Areas to consider
- Each example to be assessed and scored
  - Use of community space
  - Fulfilling an energy need
  - Barriers
- Nominate a spokes person to feed back to the group

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Community Energy Scenario's

- Scenarios
  - PV canopy on a parking garage
  - Leasing space in a commercial building
  - Using public road infrastructure
  - Community wind energy

- Common Issues
  - How to share energy when not a utility – even if a common owner
  - Distribution of the energy
  - Who installs and pays for the generation

Enabling Technology Scenario's

- Scenarios
  - Individual property owner
  - Community
  - Critical Infrastructure
  - Transit Network

- Common Issues
  - Public safety – back feeding in an outage
  - Who would own the assets
  - Economics and value proposition

Community Energy Scenarios

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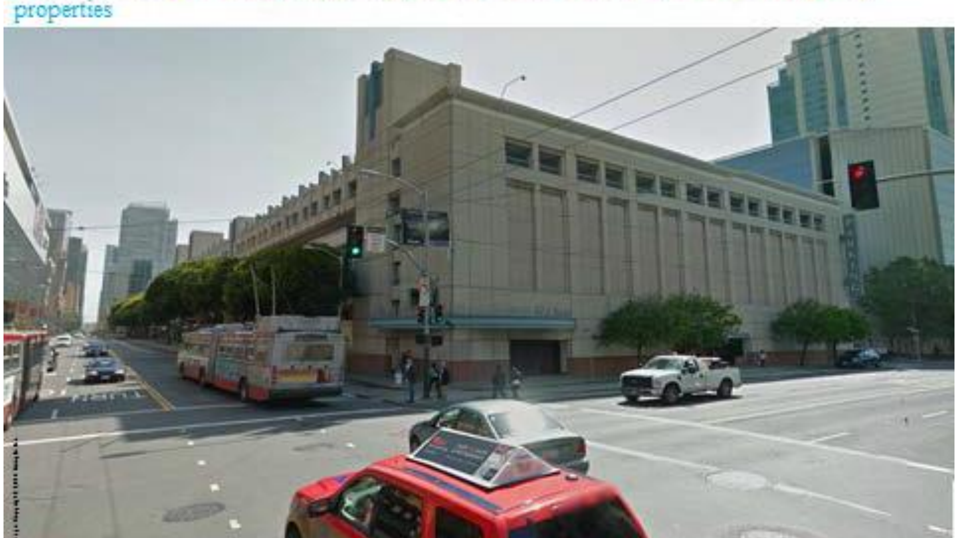
Community Generation – Scenario 1

Construction of a PV canopy on a parking garage to offset the energy needs of neighboring properties



17

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Community Generation – Scenario 1

Construction of a PV canopy on a parking garage to offset the energy needs of neighboring properties

- Consider if this a suitable location for community shared energy
- Consider would own and operate this generation asset
- Consider how can the generated energy be distributed to community members
- Consider if the garage owner owned the other properties
- Consider how can the owner of the generation, building and utility earn a fair revenue?
- Consider current regulatory polices
- Score this scenario out of 10 for the following:
  - Use of community space (10 = good use, 1 = bad)
  - Fulfilling an energy need (10= great need, 1= no need)
  - Barriers (10=none, 1= significant)

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Community Generation – Scenario 2

Leasing space in a commercial building (basement or roof) for community generation

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Community Generation – Scenario 2

Leasing space in a commercial building (basement or roof) for community generation

- Consider if this a suitable location for community shared energy
- Consider would own and operate this generation asset
- Consider how can the generated energy be distributed to community members
- Consider how can the owner of the generation, building and utility earn a fair revenue?
- Consider current regulatory polices
- Score this scenario out of 10 for the following:
  - **Use of community space** (10= good use, 1 = bad)
  - **Fulfilling an energy need** (10= great need, 1= no need)
  - **Barriers** (10=none, 1= significant)

Community Generation – Scenario 3

Using public road infrastructure for generation / energy storage (easement / integrated)

Community Generation – Scenario 3

Using public road infrastructure for generation / energy storage (easement / integrated)

- Consider if this a suitable location for community shared energy
- Consider would own and operate this generation asset
- Consider how can the generated energy be distributed to community members
- Consider how can the owner of the generation, freeway and utility earn a fair revenue?
- Consider current regulatory polices
- Score this scenario out of 10 for the following:
  - **Use of community space** (10= good use, 1 = bad)
  - **Fulfilling an energy need** (10= great need, 1= no need)
  - **Barriers** (10=none, 1= significant)

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Community Generation – Scenario 4

Community Wind in a San Francisco Park

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Community Generation – Scenario 4
Community Wind in a San Francisco Park

- Consider if this a suitable location for community shared energy
- Consider would own and operate this generation asset
- Consider how can the generated energy be distributed to community members
- Consider how can the owner of the generation, City and utility earn a fair revenue?
- Consider current regulatory polices / barriers to wind
- Score this scenario out of 10 for the following:
  - **Use of community space** (10= good use, 1 = bad)
  - **Fulfilling an energy need** (10= great need, 1= no need)
  - **Barriers** (10=none, 1= significant)

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Enabling Technology Scenarios

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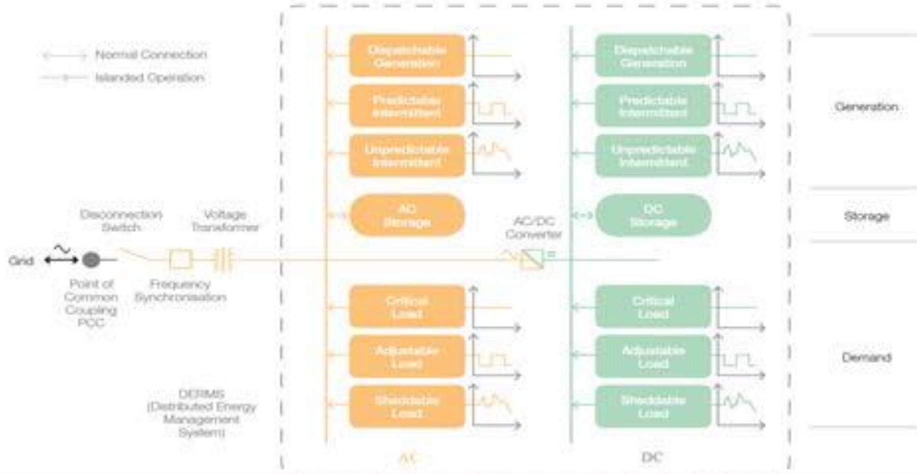
Enabling Technology – Scenario 1

Individual property owner who values self-generation and energy resilience. Property owner has the opportunity to continue to power their own development in the event of a grid outage



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Enabling Technology – Scenario 1

Individual property owner who values self-generation and energy resilience

- Consider if there a market need for such a system – what type of properties would benefit from this
- Consider the difference if the buildings are on one land parcel or separated by public streets
- Consider when, why and how the system would separate from the grid
- Consider the technology options
- Consider the economic value streams
- Consider current regulatory polices and utility implications
- Score this scenario out of 10 for the following:
  - **Use of community space** (10 = good use, 1 = bad)
  - **Fulfilling an energy need** (10 = great need, 1 = no need)
  - **Barriers** (10=none, 1= significant)

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Enabling Technology – Scenario 2

A community who value self-generation and energy resilience. Community has the opportunity to continue to have power in the event of a grid outage

Enabling Technology – Scenario 2

A community who value self-generation and energy resilience. Community has the opportunity to continue to have power in the event of a grid outage

- Consider if there a market need for such a system – what type of properties would benefit from this
- Consider the difference if the buildings are on one land parcel or separated by public streets
- Consider when, why and how the system would separate from the grid
- Consider the technology options
- Consider the economic value streams
- Consider current regulatory polices and utility implications
- Score this scenario out of 10 for the following:
  - **Use of community space** (10= good use, 1 = bad)
  - **Fulfilling an energy need** (10= great need, 1= no need)
  - **Barriers** (10=none, 1= significant)

Enabling Technology – Scenario 3

A community wide 72 hour power outage – what critical community infrastructure is important? How could these items be powered?

Enabling Technology – Scenario 3

A community wide 72 hour power outage – what critical community infrastructure is important? How could these items be powered?

- Consider where does the power come from
- Consider if community integrated storage provides the answer
- Consider what does the storage do when there is no outage
- Consider where would the equipment be located
- Consider the technology options
- Consider if there a market need for such a system – who would benefit from this?
- Score this scenario out of 10 for the following:
  - **Use of community space** (10 = good use, 1 = bad)
  - **Fulfilling an energy need** (10 = great need, 1 = no need)
  - **Barriers** (10=none, 1 = significant)

Enabling Technology – Scenario 4

Transit network has the opportunity to continue to operate in the event of a grid outage

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Enabling Technology – Scenario 4

Transit network has the opportunity to continue to operate in the event of a grid outage

- Consider the required energy to operate public transit per mile
- Consider where does the power come from
- Consider if community integrated storage provides the answer
- Consider what does the storage do when there is no outage
- Consider where would the equipment be located
- Consider the technology options
- Consider if there a market need for such a system – who would benefit from this?
- Score this scenario out of 10 for the following:
  - **Use of community space** (10= good use, 1 = bad)
  - **Fulfilling an energy need** (10= great need, 1= no need)
  - **Barriers** (10=none, 1= significant)

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Next Steps

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Next Steps

- Write up report in March
- Review Panel
- Credit in Report

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A.2 Workshop Invite

The Project

The City and County of San Francisco was awarded a grant by the California Energy Commission to investigate the feasibility for increasing Community Integrated Renewable Energy (CIRE) within the Central SoMa area of San Francisco. The grant applies to feasibility only and does not extend to implementation.

CIRE projects are projects that allow members of a community to have all, or a portion, of their energy needs to be supplied from renewable sources. This energy may be supplied on an individual property or as part of a larger shared system installed within their community.

CIRE integration has rarely been undertaken in multiple stakeholder environments in the United States but there are significant development opportunities both in California and around the globe. This project will help determine the feasibility of taking such a bold step and we need your help by participating in a workshop.

The Workshop – 11.30am – 2.30pm, January 27th

The workshop format will be a series of interactive discussions on two topics: Shared Community Generation and Island-able Smart Grids. The workshops will focus on the built environment in 2020 and will cover commercial, residential, and public assets, including both new construction and refurbishments.

Multiple scenarios will be presented around these two broad topics, and be discussed in a stepwise fashion that communicates their respective implementation. Woven throughout the scenarios are themes of entitlement, sharing, risk & resilience, and economic value. The open discussion and stakeholder feedback will then lead to a public report as part of this project

The attached document gives details about the scenarios and specific questions we are seeking feedback on at the workshop.

Why we Need You

The Central SoMa Plan (http://www.sf-planning.org/index.aspx?page=2557) and Central SoMa Eco-District Framework (http://www.sf-planning.org/ftp/files/plans-and-programs/emerging_issues/sustainable-development/CentralSoMa_EcoDTaskForceReport_112513.pdf) are acting as the catalysts to investigate CIRE opportunities and barriers for Central SoMa, and the lessons from this process will help identify opportunities and barriers for other California communities. No one person understands all of the developments and communities that will result from the plan and we want to collect your opinions and thoughts on local CIRE projects and their implications on your lives, businesses, and community.

Local energy could have some storage/microgrid opportunities and we would love your thought on this topic.

What's in it for you?

Finding the time to contribute to this workshop is a commitment. We think this commitment will be rewarded by providing you the ability to:

- Voice your opinion and shape CIRE strategies for the area
- Learn what other stakeholders are thinking for the area
- Express your viewpoint on CIRE projects
- Contribute & understand regulatory & technical opportunities & barriers.

Lunch will be provided

COMMUNITY INTEGRATED RENEWABLE ENERGY PROJECT

Scenario Assessment Workshop

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Scenario Assessment Workshop

The workshop format will be a series of interactive discussions on two topics: Shared Community Generation and Island-able Smart Grids. The workshops will focus on the built environment in 2020 and will cover new construction and refurbishments as well as commercial, residential, and public assets.

Community Shared Generation

This scenario shall investigate scenarios to increase CIRE projects within Central SoMa for developments that are constructed from 2020.

The scenario will explore the following questions, among others:

1. The requirements for local generation/storage?
2. Where generation/storage may best be sited?
3. Who would own and operate?
4. How the generation and storage energy is distributed to all the stakeholders?
5. How can this be achieved with the current regulatory framework?
6. Is there a market need?

Examples of shared community generation scenarios may include the following:

1. Construction of a PV canopy on a parking garage to offset the energy needs of neighboring community members
2. Leasing of space in a building's basement or roof area for community generation

Source: Action for Renewables

Island-able Smart Grid

This scenario shall investigate enabling technologies that will allow shared community generation and enhanced resiliency objectives to be achieved.

The scenario will explore the following questions, among others:

1. What are the limitations of the existing infrastructure?
2. What would an ideal system would look like?
3. What are the technology options?
4. What are the economic value streams?
5. Who owns and operates?
6. Is there a market need / what is the value to participants?

Examples of Island-able smart grid scenarios may include the following:

1. An individual community member who values self-generation, energy security, and resilience. What can the community member do to maximize these opportunities?
2. A single community, such as an eco-district within Central SoMa, whom value the ability to keep the lights on following a natural disaster such as an earthquake.

Source: Mitsubishi Electric

APPENDIX B:
Workshop Attendees

A full list of workshop attendees is provided below:

Name	**Company**
Ali Moaze	PG&E
Asim Tahir	Google
Avra Durack	Stem
Bruno Prestat	EDF Energy
Chase Sun	PG&E
Chris Marnay	LBNL
Cole Roberts	Arup
Danielle Murray	CCSF
David Erickson	CPUC
David Johnson	William McDonough & Partners
Doug Payne	Distributed Sun
Emma Stewart	Autodesk
Gerry Tierney	Perkins + Will
Gordon Judd	NRG
Holly Pearson	RPD

John Benson	On behalf of tri-technic
Jonathan Cherry	SFPUC
Jordan Obrien	Arup
Julian Marsh	Tishman Speyer
Kate McGee	Planning
Lewis McKnight	Gensler
Mari Hunter	SFMTA
Mark McMinn	Gensler
Molly Hoyt	PG&E
Nick Haschka	NRG
Nolan Zail	Carmel Partners
Norman D. Wong	BART
Paul Liotsakis	SF Power
Randazzo, Mark	PG&E
Russ Carr	Arup
Ryan Wartena	GELI
Sara Neff or Todd Arris	Kilroy Realty
Stacy Bradley	RPD

Stephanie Jumel	EDF Energy
Steve Moss	EDF
Steven Cismowski	RPD
Terra Weeks	SF Environment
Tim Chan	BART